EPA 340/1-80-001a

PROPERTY OF
DIVISION
OF

Stationary Source Enforcement Series

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

U.S. ENVIRONMENTAL PROTECTION AGENCY
OFFICE OF ENFORCEMENT
OFFICE OF GENERAL ENFORCEMENT
WASHINGTON, D.C. 20460

HANDBOOK DISTRIBUTION RECORD

This edition of the Standards of Performance for New Stationary Sources - A Compilation has been designed to permit selective replacement of outdated material as new standards are proposed and promulgated or existing standards are revised. A NSPS Handbook distribution record has been established and will be maintained up to date so that future revisions and additions to the document may be distributed to Handbook users: (These supplements will be issued at approximately six-month intervals.) In order to enter the Handbook user's name and address in the distribution record system, the card shown below must be filled out and mailed to the address indicated on the reverse side of card. Any future change in name and/or address should be sent to the following:

U.S. Environmental Protection Agency
Library Services Office, MD-35
Research Triangle Park, North Carolina 27711

Attn: NSPS Regulations Information

(cut along dotted line)

DISTRIBUTION RECORD CARD

NSPS Handbook User _____ (Last name) _____ (First) _____ (Middle initial) Date _____

Address to send future revisions and additions _____ (Street)

_____ (City) _____ (State) _____ (Zip code)

If address is an employer or affiliate (fill in) _____ (Employer or Affiliate name)

I have received a copy of the NSPS Handbook (EPA-340/1-77-015). Please send me any revisions and new additions to the Handbook.

U.S. ENVIRONMENTAL PROTECTION AGENCY
Library Services Office, MD-35
Research Triangle Park, North Carolina 27711

Attn: NSPS Regulations Information

EPA 340/1-80-001a

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES -

A COMPILATION AS OF JULY 1, 1980

by

PEDCo Environmental, Inc.
Cincinnati, Ohio 45246

Contract No. 68-01-4147

EPA Project Officer: Kirk Foster

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Enforcement
Office of General Enforcement
Division of Stationary Source Enforcement
Washington, D.C. 20460

July 1980

The Stationary Source Enforcement series of reports is issued by the Office of General Enforcement, Environmental Protection Agency, to assist the Regional Offices in activities related to enforcement of implementation plans, new source emission standards, and hazardous emission standards to be developed under the Clean Air Act. Copies of Stationary Source Enforcement reports are available - as supplies permit - from the U.S. Environmental Protection Agency, Office of Administration, General Services Division, MD-35, Research Triangle Park, North Carolina 27711, or may be obtained, for a nominal cost, from the National Technical Information Service, 5285 Port Royal Road, Springfield, Virginia 22151.

PREFACE

This document is a compilation of the New Source Performance Standards promulgated under Section 111 of the Clean Air Act, represented in full as amended. The information contained herein updates the original compilation published by the Environmental Protection Agency in August 1976 and Supplement I issued in March 1977 (EPA 340/1-76-009 and 340/1-76-009a).

The format of this document permits easy and convenient replacement of material as new standards are proposed and promulgated or existing standards revised. Section I is an introduction to the standards, explaining their purpose and interpreting the working concepts which have developed through their implementation. Section II contains a "quick-look" summary of each standard, including the dates of proposal, promulgation, and any subsequent revisions. Section III is the complete standards with all amendments incorporated into the material. Section IV contains the full text of all revisions, including the preamble which explains the rationale behind each revision. Section V is all proposed amendments to the standards. To facilitate the addition of future materials, the punched, loose-leaf format was selected. This approach permits the document to be placed in a three-ring binder or to be secured by rings, rivets, or other fasteners; future revisions can then be easily inserted.

Future Supplements to New Source Performance Standards - A Compilation will be issued on an as needed basis by the Division of Stationary Source Enforcement. Comments and suggestions regarding this document should be directed to: Standards Handbooks, Division of Stationary Source Enforcement (EN-341), U.S. Environmental Protection Agency, Washington, D.C. 20460.

TABLE OF CONTENTS

		Page
I.	INTRODUCTION TO STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES	I-1
II.	SUMMARY OF STANDARDS AND REVISIONS	II-1
III.	PART 60 - STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES	III-1

SUBPART A - GENERAL PROVISIONS

Section		
60.1	Applicability	III-4
60.2	Definitions	III-4
60.3	Abbreviations	III-4
60.4	Address	III-5
60.5	Determination of construction or modification	III-7
60.6	Review of plans	III-7
60.7	Notification and recordkeeping	III-7
60.8	Performance tests	III-7
60.9	Availability of information	III-8
60.10	State authority	III-8
60.11	Compliance with standards and maintenance requirements	III-8
60.12	Circumvention	III-8
60.13	Monitoring requirements	III-8
60.14	Modification	III-10
60.15	Reconstruction	III-11
60.16	Priority List	III-11

SUBPART B - ADOPTION AND SUBMITTAL OF STATE PLANS FOR DESIGNATED FACILITIES

Section		
60.20	Applicability	III-13
60.21	Definitions	III-13
60.22	Publication of guideline documents, emission guidelines, final compliance times	III-13

TABLE OF CONTENTS

Section		Page
60.23	Adoption and submittal of state plans; public hearings	III-13
60.24	Emission standards and compliance schedules	III-14
60.25	Emission inventories, source surveillance reports	III-14
60.26	Legal authority	III-15
60.27	Actions by the Administrator	III-15
60.28	Plan revisions by the State	III-15
60.29	Plan revisions by the Administrator	III-15
	SUBPART C - EMISSION GUIDELINES AND COMPLIANCE TIMES	III-16
	SUBPART D - STANDARDS OF PERFORMANCE FOR FOSSIL-FUEL-FIRED STEAM GENERATORS FOR WHICH CONSTRUCTION IS COMMENCED AFTER AUGUST 17, 1971	
Section		
60.40	Applicability and designation of affected facility	III-17
60.41	Definitions	III-17
60.42	Standard for particulate matter	III-17
60.43	Standard for sulfur dioxide	III-17
60.44	Standard for nitrogen oxides	III-17
60.45	Emission and fuel monitoring	III-18
60.46	Test methods and procedures	III-19
	SUBPART Da - STANDARDS OF PERFORMANCE FOR ELECTRIC UTILITY STEAM GENERATING UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER SEPTEMBER 18, 1978	
Section		
60.40a	Applicability and designation of affected facility	III-21
60.41a	Definitions	III-21
60.42a	Standard for particulate matter	III-22
60.43a	Standard for sulfur dioxide	III-22
60.44a	Standard for nitrogen oxides	III-23

TABLE OF CONTENTS

Section		Page
60.45a	Commercial demonstration permit	III-23
60.46a	Compliance provisions	III-24
60.47a	Emission monitoring	III-24
60.48a	Compliance determination procedures and methods	III-25
60.49a	Reporting requirements	III-26

SUBPART E - STANDARDS OF PERFORMANCE FOR INCINERATORS

Section		
60.50	Applicability and designation of affected facility	III-28
60.51	Definitions	III-28
60.52	Standard for particulate matter	III-28
60.53	Monitoring of operations	III-28
60.54	Test methods and procedures	III-28

SUBPART F - STANDARDS OF PERFORMANCE FOR PORTLAND CEMENT PLANTS

Section		
60.60	Applicability and designation of affected facility	III-29
60.61	Definitions	III-29
60.62	Standard for particulate	III-29
60.63	Monitoring of operations	III-29
60.64	Test methods and procedures	III-29

SUBPART G - STANDARDS OF PERFORMANCE FOR NITRIC ACID PLANTS

Section		
60.70	Applicability and designation of affected facility	III-30
60.71	Definitions	III-30
60.72	Standard for nitrogen oxides	III-30
60.73	Emission monitoring	III-30
60.74	Test methods and procedures	III-30

TABLE OF CONTENTS

Page

SUBPART H - STANDARDS OF PERFORMANCE FOR SULFURIC ACID PLANTS

Section

60.80	Applicability and designation of affected facility	III-31
60.81	Definitions	III-31
60.82	Standard for sulfur dioxide	III-31
60.83	Standard for acid mist	III-31
60.84	Emission monitoring	III-31
60.85	Test methods and procedures	III-31

SUBPART I - STANDARDS OF PERFORMANCE FOR ASPHALT CONCRETE PLANTS

Section

60.90	Applicability and designation of affected facility	III-32
60.91	Definitions	III-32
60.92	Standard for particulate matter	III-32
60.93	Test methods	III-32

SUBPART J - STANDARDS OF PERFORMANCE FOR PETROLEUM REFINERIES

Section

60.100	Applicability and designation of affected facility	III-33
60.101	Definitions	III-33
60.102	Standard for particulate matter	III-33
60.103	Standard for carbon monoxide	III-33
60.104	Standard for sulfur dioxide	III-33
60.105	Emission monitoring	III-33
60.106	Test methods and procedures	III-34

TABLE OF CONTENTS

Page

SUBPART K - STANDARDS OF PERFORMANCE FOR STORAGE VESSELS FOR PETROLEUM LIQUIDS CONSTRUCTED AFTER JUNE 11, 1973 AND PRIOR TO MAY 19, 1978

Section		
60.110	Applicability and designation of affected facility	III-36
60.111	Definitions	III-36
60.112	Standard for volatile organic compounds (VOC)	III-36
60.113	Monitoring of operations	III-36

SUBPART Ka - STANDARDS OF PERFORMANCE FOR STORAGE VESSELS FOR PETROLEUM LIQUIDS CONSTRUCTED AFTER MAY 18, 1978

Section		
60.110a	Applicability and designation of affected facility	III-37
60.111a	Definitions	III-37
60.112a	Standard for volatile organic compounds (VOC)	III-37
60.113a	Testing and procedures	III-38
60.114a	Equivalent equipment and procedures	III-38
60.115a	Monitoring of operations	III-39

SUBPART L - STANDARDS OF PERFORMANCE FOR *SECONDARY LEAD SMELTERS*

Section		
60.120	Applicability and designation of affected facility	III-40
60.121	Definitions	III-40
60.122	Standard for particulate matter	III-40
60.123	Test methods and procedures	III-40

TABLE OF CONTENTS

Page

SUBPART M - STANDARDS OF PERFORMANCE FOR SECONDARY BRASS AND BRONZE INGOT PRODUCTION PLANTS

Section

60.130 Applicability and designation of affected facility III-41
60.131 Definitions III-41
60.132 Standard for particulate matter III-41
60.133 Test methods and procedures III-41

SUBPART N - STANDARDS OF PERFORMANCE FOR IRON AND STEEL PLANTS

Section

60.140 Applicability and designation of affected facility III-42
60.141 Definitions III-42
60.142 Standard for particulate matter III-42
60.143 Monitoring of operations III-42
60.144 Test methods and procedures III-42

SUBPART O - STANDARDS OF PERFORMANCE FOR SEWAGE TREATMENT PLANTS

Section

60.150 Applicability and designation of affected facility III-43
60.151 Definitions III-43
60.152 Standard for particulate matter III-43
60.153 Monitoring of operations III-43
60.154 Test methods and procedures III-43

SUBPART P - STANDARDS OF PERFORMANCE FOR PRIMARY COPPER SMELTERS

Section

60.160 Applicability and designation of affected facility III-44
60.161 Definitions III-44

TABLE OF CONTENTS

		Page
60.162	Standard for particulate matter	III-44
60.163	Standard for sulfur dioxide	III-44
60.164	Standard for visible emissions	III-44
60.165	Monitoring of operations	III-44
60.166	Test methods and procedures	III-45

SUBPART Q - STANDARDS OF PERFORMANCE FOR PRIMARY ZINC SMELTERS

Section		
60.170	Applicability and designation of affected facility	III-46
60.171	Definitions	III-46
60.172	Standard for particulate matter	III-46
60.173	Standard for sulfur dioxide	III-46
60.174	Standard for visible emissions	III-46
60.175	Monitoring of operations	III-46
60.176	Test methods and procedures	III-46

SUBPART R - STANDARDS OF PERFORMANCE FOR PRIMARY LEAD SMELTERS

Section		
60.180	Applicability and designation of affected facility	III-47
60.181	Definitions	III-47
60.182	Standard for particulate matter	III-47
60.183	Standard for sulfur dioxide	III-47
60.184	Standard for visible emissions	III-47
60.185	Monitoring of operations	III-47
60.186	Test methods and procedures	III-47

TABLE OF CONTENTS

Page

SUBPART S - STANDARDS OF PERFORMANCE FOR PRIMARY ALUMINUM REDUCTION PLANTS

Section		
60.190	Applicability and designation of affected facility	III-48
60.191	Definitions	III-48
60.192	Standard for fluorides	III-48
60.193	Standard for visible emissions	III-48
60.194	Monitoring of operations	III-48
60.195	Test methods and procedures	III-48

SUBPART T - STANDARDS OF PERFORMANCE FOR PHOSPHATE FERTILIZER INDUSTRY: WET PROCESS PHOSPHORIC ACID PLANTS

Section		
60.200	Applicability and designation of affected facility	III-50
60.201	Definitions	III-50
60.202	Standard for fluorides	III-50
60.203	Monitoring of operations	III-50
60.204	Test methods and procedures	III-50

SUBPART U - STANDARDS OF PERFORMANCE FOR PHOSPHATE FERTILIZER INDUSTRY: SUPERPHOSPHORIC ACID PLANTS

Section		
60.210	Applicability and designation of affected facility	III-51
60.211	Definitions	III-51
60.212	Standard for fluorides	III-51
60.213	Monitoring of operations	III-51
60.214	Test methods and procedures	III-51

TABLE OF CONTENTS

Page

SUBPART V - STANDARDS OF PERFORMANCE FOR PHOSPHATE FERTILIZER INDUSTRY: DIAMMONIUM PHOSPHATE PLANTS

Section		
60.220	Applicability and designation of affected facility	III-52
60.221	Definitions	III-52
60.222	Standard for fluorides	III-52
60.223	Monitoring of operations	III-52
60.224	Test methods and procedures	III-52

SUBPART W - STANDARDS OF PERFORMANCE FOR PHOSPHATE FERTILIZER INDUSTRY: TRIPLE SUPERPHOSPHATE PLANTS

Section		
60.230	Applicability and designation of affected facility	III-53
60.231	Definitions	III-53
60.232	Standard for fluorides	III-53
60.233	Monitoring of operations	III-53
60.234	Test methods and procedures	III-53

SUBPART X - STANDARDS OF PERFORMANCE FOR THE PHOSPHATE FERTILIZER INDUSTRY: GRANULAR TRIPLE SUPERPHOSPHATE STORAGE FACILITIES

Section		
60.240	Applicability and designation of affected facility	III-54
60.241	Definitions	III-54
60.242	Standard for fluorides	III-54
60.243	Monitoring of operations	III-54
60.244	Test methods and procedures	III-54

TABLE OF CONTENTS

Page

SUBPART Y - STANDARDS OF PERFORMANCE FOR COAL PREPARATION PLANTS

Section

60.250	Applicability and designation of affected facility	III-55
60.251	Definitions	III-55
60.252	Standards for particulate matter	III-55
60.253	Monitoring of operations	III-55
60.254	Test methods and procedures	III-55

SUBPART Z - STANDARDS OF PERFORMANCE FOR FERROALLOY PRODUCTION FACILITIES

Section

60.260	Applicability and designation of affected facility	III-56
60.261	Definitions	III-56
60.262	Standard for particulate matter	III-56
60.263	Standard for carbon monoxide	III-56
60.264	Emission monitoring	III-56
60.265	Monitoring of operations	III-56
60.266	Test methods and procedures	III-57

SUBPART AA - STANDARDS OF PERFORMANCE FOR STEEL PLANTS: ELECTRIC ARC FURNACES

Section

60.270	Applicability and designation of affected facility	III-59
60.271	Definitions	III-59
60.272	Standard for particulate matter	III-59
60.273	Emission monitoring	III-59
60.274	Monitoring of operations	III-59
60.275	Test methods and procedures	III-60

TABLE OF CONTENTS

Page

SUBPART BB - STANDARDS OF PERFORMANCE FOR KRAFT PULP MILLS

Section

60.280	Applicability and designation of affected facility	III-61
60.281	Definitions	III-61
60.282	Standard for particulate matter	III-61
60.283	Standard for total reduced sulfur (TRS)	III-61
60.284	Monitoring of emissions and operations	III-62
60.285	Test methods and procedures	III-62

SUBPART DD - STANDARDS OF PERFORMANCE FOR GRAIN ELEVATORS

Section

60.300	Applicability and designation of affected facility	III-64
60.301	Definitions	III-64
60.302	Standard for particulate matter	III-64
60.303	Test methods and procedures	III-64
60.304	Modification	III-64

SUBPART GG - STANDARDS OF PERFORMANCE FOR STATIONARY GAS TURBINES

Section

60.330	Applicability and designation of affected facility	III-66
60.331	Definitions	III-66
60.332	Standard for nitrogen oxides	III-66
60.333	Standard for sulfur dioxide	III-67
60.334	Monitoring of operations	III-67
60.335	Test methods and procedures	III-67

TABLE OF CONTENTS

Page

SUBPART HH - STANDARDS OF PERFORMANCE
FOR LIME MANUFACTURING PLANTS

Section		
60.340	Applicability and designation of affected facility	III-69
60.341	Definitions	III-69
60.342	Standard for particulate matter	III-69
60.343	Monitoring of emissions and operations	III-69
60.344	Test methods and procedures	III-69

TABLE OF CONTENTS

		Page
APPENDIX A - REFERENCE METHODS		
Method 1	- Sample and velocity traverses for stationary sources	III-Appendix A-1
Method 2	- Determination of stack gas velocity and volumetric flow rate (Type S Pitot Tube)	III-Appendix A-4
Method 3	- Gas analysis for carbon dioxide, excess air, and dry molecular weight	III-Appendix A-14
Method 4	- Determination of moisture in stack gases	III-Appendix A-17
Method 5	- Determination of particulate emissions from stationary sources	III-Appendix A-21
Method 6	- Determination of sulfur dioxide emissions from stationary sources	III-Appendix A-28
Method 7	- Determination of nitrogen oxide emissions from stationary sources	III-Appendix A-30
Method 8	- Determination of sulfuric acid mist and sulfur dioxide emissions from stationary sources	III-Appendix A-32
Method 9	- Visual determination of the opacity of emissions from stationary sources	III-Appendix A-35
Method 10	- Determination of carbon monoxide emissions from stationary sources	III-Appendix A-39
Method 11	- Determination of hydrogen sulfide content of fuel gas streams in petroleum refineries	III-Appendix A-41
Method 12	- [Reserved]	
Method 13A	- Determination of total fluoride emissions from stationary sources - SPADNS Zirconium Lake Method	III-Appendix A-45
Method 13B	- Determination of total fluoride emissions from stationary sources - Specific Ion Electrode method	III-Appendix A-50
Method 14	- Determination of fluoride emissions from potroom roof monitors of primary aluminum plants	III-Appendix A-52

Page

Method 15 - Determination of hydrogen sulfide, carbonyl sulfide, and carbon desulfide emissions from stationary sources — III-Appendix A-57

Method 16 - Semicontinuous determination of sulfur emissions from stationary sources — III-Appendix A-6C

Method 17 - Determination of particulate emissions from stationary sources (in-stack filtration method) — III-Appendix A-68

Method 19 - Determination of sulfur dioxide removal efficiency and particulate, sulfur dioxide and nitrogen oxides emission rates from electric utility steam generators — III-Appendix A-79

Method 20 - Determination of nitrogen oxides, sulfur dioxide, and oxygen emissions from stationary gas turbines — III-Appendix A-85

APPENDIX B - PERFORMANCE SPECIFICATIONS — III-Appendix B-1

APPENDIX C - DETERMINATION OF EMISSION RATE CHANGE — III-Appendix C-1

APPENDIX D - REQUIRED EMISSION INVENTORY INFORMATION — III-Appendix D-1

IV. FULL TEXT OF REVISIONS (References) — IV-1

V. PROPOSED AMENDMENTS — V-1

I INTRODUCTION

The Clean Air Act of 1970, building on prior Federal, state and local control agency legislation and experience, authorized a national program of air pollution prevention and control which included receptor/effect and specification standards, emission standards for mobile sources, and - for the first time - nationwide uniform emission standards for new and modified stationary sources. This is a compilation of the emission standards authorized in Section 111 of the Act: Standards of Performance for New Stationary Sources, commonly referred to as new source performance standards or NSPS.

Taking up less than two pages of the 56-page Clean Air Act, NSPS have become an important and integral part of Federal air pollution control activities. The major purpose of NSPS is that of preventing new air pollution problems. Section 111 of the 1970 Act, therefore, requires the application of the best adequately demonstrated system of emission reduction (taking into account the cost), permits control of existing sources which increase emissions, and can be applied to both new and existing sources of a pollutant not regulated by Sections 109 and 112. Standards may apply to specific equipment and processes, or to entire plants and facilities [Section 111(b)(2)], and may be revised whenever necessary. Since the standards are based on emissions, the owner or operator of a source may select any control system desired, but he must achieve the standard. Installation and operation of a control system

is not enough: compliance is based on actual emissions. Finally, there is no provision for variances or exemptions; the NSPS must be met during normal operation (start-up, shutdown, and malfunction periods are provided for in specific regulations).

In developing NSPS or determining whether violations of NSPS have occurred, Section 114 of the Act permits EPA to require an owner or operator to keep records, make reports, monitor, sample emissions, and provide other information. Section 114 also grants EPA rights of entry, access to records and monitoring systems, and authority to sample emissions.

NSPS may be used to complement other standards (ambient air quality, hazardous pollutant, or mobile source), or may constitute the sole approach to controlling a specific air pollutant or air pollution source. The National Ambient Air Quality Standards (NAAQS) are attained through state implementation plans (SIP) and mobile source emission standards. The SIP are based on emission inventories. NSPS provide the standard test methods and accurate emission measurements required for a meticulous emission inventory. The emission measurements made during NSPS development can be used to support SIP regulations, and usually prove easier to enforce than a general regulation because they are tailored to specific sources. By imposing more stringent control on new sources, NSPS extend the usefulness of SIP's and of control equipment by reducing the rate at which emissions increase.

Protection of air quality is also aided by NSPS. No significant deterioration (non-degradation) regulations, as a minimum, require that SIP apply best available control technology to specified categories of new sources. Usually, NSPS will represent best technology. For sources not subject to NSPS, selection of best available control technology may be aided by NSPS studies and by transfer of NSPS-determined technology between similar industries.

Hazardous pollutant standards which do not require absolute best control to protect public health can be supplemented by NSPS that (1) minimize environmental accumulation of the pollutant if long-term effects are suspected and (2) increase margins of safety gradually, with less economic impact, by requiring best control of new sources. Even if the hazardous pollutant standard represents best existing technology, NSPS can be applied as control technology improves, increasing the margin of safety without penalizing existing plants.

Finally, NSPS can be used alone to control emissions of designated pollutants. This is the most feasible approach when emissions of a pollutant could endanger public health or welfare if not limited, but the number of existing sources is small. In situations where neither hazardous nor ambient air standards are justified, NSPS may be used. Public health could, for example, be endangered yet there could be insufficient data to set ambient air standards that would with certainty protect the public. Or a pollutant may affect public welfare, but

not public health, another situation where NSPS could be used instead of the more complex SIP approach.

NSPS Working Concepts

The development of working concepts and standard-setting processes for both NSPS and hazardous pollutant standards reflects interpretations of the Act that have evolved, and continue to evolve, during its implementation.

Affected facility. The term "affected facility" does not appear in the Act, but is used in NSPS regulations to identify the equipment/system/process to which an NSPS applies. This concept permits full utilization of the authority in Section 111(b)(2) to "distinguish among classes, types, and sizes within categories." Affected facilities range from process equipment (cement plant kilns) to entire plants (asphalt concrete, nitric acid). Some NSPS exempt facilities below a specified size (steam generators, storage tanks). Distinctions may also be made between the materials used (different standards for coal, oil, and gas fired steam generators) or the material produced (different electric arc furnace standards for ferroalloys and steel production).

Standards of performance. Senate Report No. 91-1196 explains that this refers to the degree of control which can be achieved. EPA is to determine achievable limits and let the owner or operator determine the most economically acceptable technique to apply. The definition appearing in the 1970 Act contains two phrases which also require explanation:

(a) Emission limitations. This term refers to the maximum allowable quantity of concentration of pollutant that

may be emitted to the atmosphere. Standard test methods are absolutely essential to the establishment of emission limitations, because different methods yield different results. The test method used to collect data for the standard must be used to determine compliance unless a correlation with other test methods is established. Several attempts have been made to correlate particulate matter test methods, but statistical analyses of these data indicate that sampling errors and process and other variations mask any correlation that may exist. Even if such correlations do exist, they will very probably differ for each source category.

An advantage of emission limitations is that any system of control may be applied; the owner/operator is responsible only for meeting the standard. This helps assure proper maintenance and permits innovative control techniques, but can create problems if well-designed, properly operated control equipment for some reason exceeds allowable emission levels. In addition, when a large number of small sources, such as stationary internal combustion engines, are involved, the cost of even a single performance test can be a significant fraction of the cost of the unit. For standardized units like gas turbines, prototype testing could be substituted, but a few categories (petroleum product storage tanks, for example) may best be regulated with equipment standards.

(b) Best system of emission reduction. In the selection of this system, the Act requires that the cost of achieving such reduction be taken into account and that the system be adequately demonstrated. The latter stipulation does not necessarily require that the system be in widespread use or even that it be in full-scale use at all. Experimental results could suffice, as could reasonable transfer of technology from one category to another. In practice, however, the system selected is usually the best available full-scale operating system. This should be expected, since a well-controlled existing plant provides actual cost figures, emission data, and operating and reliability information that experimental results cannot.

An NSPS applies nationwide over tremendous geographic, geologic, and climatic variations. Standards must therefore provide for differences in raw materials (whether friability of different coals affects coal cleaning plant emissions), weather (whether scrubbers can operate during Alaskan winters), operating parameters (whether seldom operated emergency power supply gas turbines should be controlled), and other factors. These variables are especially important because there is no provision for granting variances from NSPS, other than total exclusion or a separate NSPS.

Stationary sources. A stationary source is any potential or actual source of air pollution. This has come to include, by implication, the control system and ducting which handles the exhaust gases from the source. An affected facility is then a new or modified stationary source to which a standard applies.

Modification. Basically a modification is any change in an existing source which increases emissions. EPA has interpreted this as applying only to emissions to the atmosphere from sources for which NSPS have been proposed or promulgated, and has excluded some changes from the definition (such as increases in the hours of operation). Determination of modification can, however, become complex. The regulation defining modifications was promulgated on December 16, 1975.

Designated pollutants. When the pollutant for which an NSPS is set is not listed as either a hazardous (Section 112) or a criteria (Section 108) pollutant, it is defined as a designated pollutant and action under Section 111(d) of the Act is initiated. In a process similar to that required for state implementation plans, states are to establish existing source emission standards for this designated pollutant and submit control plans to EPA. Standards and control plans are required only for existing sources to which the NSPS apply if such sources were new sources.

Regulations establishing this procedure have been difficult to formulate; the role of state agencies in the determination of best control of existing sources is probably the most controversial issue. The regulation promulgated on November 17, 1975, specifies that EPA either issues guidelines (welfare pollutants) or an emission value

(health pollutants) which states are to utilize in a manner analogous to the SIP process.

Continuous monitoring. The lack of a variance process, the need to account for nationwide process variations, and the implications of emission standards that must be attained: all point to the need for continuous air pollutant emission monitoring. Present manual source test methods require such a high investment in both funds and personnel that they may be used only once every six months or year to determine compliance. Such tests reveal almost nothing about the effect of process or raw material variations on emissions.

As a first step in improving emission data gathering and in moving toward the next step in emission standards, EPA is requiring continuous monitoring on certain pollutant-affected facility combinations. Regulations promulgated on October 6, 1975, specify performance criteria that continuous monitoring instruments installed as NSPS requirements must meet. Specified "continuous" data output ranges from the second-by-second opacity meter readings to the once every 15 minutes output from NO_x instruments.

This document contains all New Source Performance Standards, promulgated under Section 111 of the Clean Air Act, represented in full as amended. As more sources of pollution are investigated and new technology developed, the New Source Performance Standards will continue to be updated to achieve their primary purpose of preventing new air pollution problems.

Gary D. McCutchen
U.S. Environmental Protection Agency

SECTION II

SUMMARY OF STANDARDS AND REVISIONS

II. SUMMARY OF STANDARDS AND REVISIONS

In order to make the information in this document more easily acessible, a summary has been prepared of all New Source Performance Standards promulgated since their inception in December 1971. Anyone who must use the Federal Register frequently to refer to regulations published by Federal agencies is well aware of the problems of sifting through the many pages to extract the "meat" of a regulation. Although regulatory language is necessary to make the intent of a regulation clear, a more concise reference to go to when looking up a particular standard would be helpful. With this in mind, the following table was developed to assist those who work with the NSPS. It includes the categories of stationary sources and the affected facilities to which the standards apply; the pollutants which are regulated and the levels to which they must be controlled; and the requirements for monitoring emissions and operating parameters. Before developing standards for a particular source category, EPA must first identify the pollutants emitted and determine that they contribute significantly to air pollution which endangers public health or welfare. The standards are then developed and proposed in the Federal Register. After a period of time during which the public is encouraged to submit comments on the proposal, appropriate revisions are made to the regulations and they are

promulgated in the Federal Register. To cite such a promulgation, it is common to refer to it by volume and page number, i.e. 36 FR 24876, which means Volume 36, page 24876 of the Federal Register. The table gives such references for the proposal, promulgation and subsequent revisions of each standard listed.

Linda S. Chaput
U.S. Environmental
Protection Agency

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart D - Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971				
Proposed/effective 8/17/71 (36 FR 15704)	Coal, coal/wood residue fired boilers >250 million Btu/h	Particulate Opacity SO_2 NO_x	0.10 lb/10^6 Btu 20%; 27% 6 min/h* 1.2 lb/10^6 Btu 0.70 lb/10^6 Btu	No requirement Continuous Continuous* Continuous*
Promulgated 12/23/71 (36 FR 24876)	Oil, oil/wood residue fired boilers >250 million Btu/h	Particulate Opacity SO_2 NO_x	0.10 lb/10^6 Btu 20%; 27% 6 min/h 0.80 lb/10^6 Btu 0.30 lb/10^6 Btu	No requirement Continuous Continuous* Continuous*
Revised 7/26/72 (37 FR 14877) 10/15/73 (38 FR 28564) 6/14/74 (39 FR 20790) 1/16/75 (40 FR 2803)	Gas, gas/wood residue fired boilers >250 million Btu/h	Particulate Opacity NO_x	0.10 lb/10^6 Btu 20%; 27% 6 min/h 0.20 lb/10^6 Btu	No requirement Continuous* Continuous*
10/6/75 (40 FR 46250) 12/22/75 (40 FR 59204) 11/22/76 (41 FR 51397) 1/31/77 (42 FR 5936) 7/25/77 (42 FR 37936) 8/15/77 (42 FR 41122)	Mixed fossil fuel fired boilers >250 million Btu/h	Particulate Opacity SO_2 NO_x (except lignite or 25% coal refuse)	0.10 lb/10^6 Btu 20%; 27% 6 min/h Prorated Prorated	No requirement Continuous Continuous* Continuous*
8/17/77 (42 FR 41122) 12/5/77 (42 FR 61537) 3/3/78 (43 FR 8800) 3/7/78 (43 FR 9276) 1/17/79 (44 FR 3491) 6/11/79 (44 FR 33580) 12/28/79 (44 FR 76786) 2/6/80 (45 FR 8211) 5/29/80 (45 FR 36077)	Lignite, lignite/wood residue >250 million Btu/h	Particulate Opacity SO_2 NO_x (as of 12/22/76)	0.10 lb/10^6 Btu 20%; 27% 6 min/h 1.2 lb/10^6 Btu 0.60 lb/10^6 Btu 0.80 lb/10^6 Btu for ND, SD, MT lignite burned in cyclone-fired unit *exceptions; see §60.42(b)	No requirement Continuous Continuous* Continuous* *exceptions; see standards

Source category	Affected facility	Pollutant	Emission level	Potential combustion concentration	Reduction of potential combustion concentration, %	Monitoring requirement
Subpart Da - Electric utility steam generating units for which construction is commenced after September 18, 1978	Boilers >73 MW (>250 million Btu/h) firing solid and solid derived fuel	Particulate	13 ng/J (0.03 lb/million Btu)	3000 ng/J (7.0 lb/million Btu)	99	No requirement
		Opacity	20%; 27% 6 min/h			Continuous
		SO_2	520 ng/J (1.20 lb/million Btu)	See 60.48a(b)	90	Continuous
			or			
			<260 ng/J (0.60 lb/million Btu)	See 60.48a(b)	70	Continuous
Proposed/effective 9/19/78 (43 FR 42154)		SO_2 - solvent refined coal	520 ng/J (1.20 lb/million Btu)	See 60.48a(b)	85	Continuous
Promulgated 6/11/79 (44 FR 33580)		SO_2 - 100% anthracite; non-continental	520 ng/J (1.20 lb/million Btu)		Exempt	Continuous
		NO_x - coal derived fuels; subbituminous; shale oil	210 ng/J (0.50 lb/million Btu)	990 ng/J (2.30 lb/million Btu)	65	Continuous
Revised 2/6/80 (45 FR 8211)		NO_x - >25% lignite mined in ND, SD, MT, combusted in slag tap furnace	340 ng/J (0.80 lb/million Btu)	990 ng/J (2.30 lb/million Btu)	65	Continuous
		NO_x - lignite; bituminous anthracite; other fuels	260 ng/J (0.60 lb/million Btu)	990 ng/J (2.30 lb/million Btu)	65	Continuous

Source category	Affected facility	Pollutant	Emission level	Potential combustion concentration	Reduction of potential combustion concentration, %	Monitoring requirement
	Boilers >73 MW (>250 million Btu/h) firing liquid fuel	Particulate	13 ng/J (0.03 lb/million Btu)	75 ng/J (0.17 lb/million Btu)	70	No requirement
		Opacity	20%; 27% 6 min/h			Continuous
		SO_2	340 ng/J (0.80 lb/million Btu)	See 60.48a(b)	90	Continuous
			or			
			<86 ng/J (0.20 lb/million Btu)	See 60.48a(b)	0	Continuous
		SO_2 (non-continental)	340 ng/J (0.80 lb/million Btu)	See 60.48a(b)	Exempt	Continuous
		NO_x	130 ng/J (0.30 lb/million Btu)	310 ng/J (0.72 lb/million Btu)	30	Continuous
	Boilers >73 MW (>250 million Btu) firing gaseous fuels	Particulate	13 ng/J (0.03 lb/million Btu)			No requirement
		Opacity	20%; 27% 6 min/h			No requirement
		SO_2	340 ng/J (0.80 lb/million Btu)	See 60.48a(b)	90	Continuous*
			or			
			<86 ng/J (0.20 lb million Btu)	See 60.48a(b)	0	Continuous*
		SO_2 (non-continental)	340 ng/J (0.80 lb/million Btu)	See 60.48a(b)	Exempt	Continuous*
		NO_x	86 ng/J (0.20 lb/million Btu)	290 ng/J (0.67 lb/million Btu)	25	Continuous

*Except when using only natural gas.

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart E - Incinerators				
Proposed/effective 8/17/71 (36 FR 15704)	Incinerators >50 tons/day	Particulate	0.08 gr/dscf (0.18 g/dscm) corrected to 12% CO_2	No requirement
Promulgated 12/23/71 (36 FR 24876)				
Revised 6/14/74 (36 FR 20790) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				Daily charging rates and hours
Subpart F - Portland Cement Plants				
Proposed/effective 8/17/71 (36 FR 15704)	Kiln	Particulate Opacity	0.30 lb/ton 20%	No requirement No requirement
Promulgated 12/23/71 (36 FR 24876)	Clinker cooler	Particulate Opacity	0.10 lb/ton 10%	No requirement No requirement
Revised 6/14/74 (39 FR 20790) 11/12/74 (39 FR 39872) 10/6/75 (40 FR 46250) //25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)	Fugitive emission points	Opacity	10%	No requirement Daily production and feed kiln rates

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart G - Nitric Acid Plants				
Proposed/effective 8/17/71 (36 FR 15704)	Process equipment	Opacity	10%	No requirement
		NO_x	3.0 lb/ton	Continuous
Promulgated 12/23/71 (36 FR 24876)				
Revised 5/23/73 (38 FR 13562) 10/15/73 (38 FR 28564) 6/14/74 (39 FR 20790) 10/6/75 (40 FR 46250) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				Daily production rates and hours
Subpart H - Sulfuric Acid Plants				
Proposed/effective 8/17/71 (36 FR 15704)	Process equipment	SO_2	4.0 lb/ton	Continuous
		Acid mist	0.15 lb/ton	No requirement
Promulgated 12/23/71 (36 FR 24876)		Opacity	10%	No requirement
Revised 5/23/73 (38 FR 13562) 10/15/73 (38 FR 28564) 6/14/74 (39 FR 20790) 10/6/75 (40 FR 46250) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart I - Asphalt Concrete Plants				
Proposed/effective 6/11/73 (38 FR 15406)	Dryers; screening and weighing systems; storage, transfer, and loading systems; dust handling equipment	Particulate	0.04 gr/dscf (90 mg/dscm)	No requirement
		Opacity	20%	No requirement
Promulgated 3/8/74 (39 FR 9308)				
Revised 10/6/75 (40 FR 46250) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800) 8/31/79 (44 FR 51225)				
Subpart J - Petroleum Refineries				
Proposed/effective 6/11/73 (38 FR 15406) 10/4/76 (41 FR 43866)	Catalytic cracker	Particulate	1.0 lb/1000 lb (1.0 kg/1000 kg)	No requirement
	(with incinerator or waste heat boiler)		Additional 0.10 lb/10^6 Btu (43.0 g/MJ)	No requirement
Promulgated 3/8/74 (39 FR 9308)				
Revised 10/6/75 (40 FR 46250)		Opacity	30%; 6 min. exemption	Continuous
6/24/77 (42 FR 32426) 7/25/77 (42 FR 37936)		CO	0.05%	Continuous
8/4/77 (42 FR 39389) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800) 3/15/78 (43 FR 10866)	Fuel gas combustion	SO_2	0.10 gr H_2S/dscf (230 mg/dscm) fuel gas content	Continuous
3/12/79 (44 FR 13480) 10/25/79 (44 FR 61542)	Claus sulfur recovery plants >20 LTD/day (as of 10/4/76)	SO_2	0.025% with oxidation or reduction and incineration; 0.030% with reduction only	Continuous Continuous

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart K - Storage Vessels for Petroleum Liquids Constructed After June 11, 1973 and Prior to May 19, 1978 Proposed/effective 6/11/73 (38 FR 15406) Promulgated 3/8/74 (39 FR 9308) Revised 4/17/74 (39 FR 13776) 6/14/74 (39 FR 20790) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800) 4/4/80 (45 FR 23374)	Storage tanks >65,000 gal. capacity (246,052 liters) as of 6/11/73 and >40,000 gal. capacity (151,412 liters) as of 3/8/74	Volatile organic compounds (VOC)	Vapor pressure 1.5-11.1 psia (78-570 mm Hg), equip with floating roof, vapor recovery system, or equivalent Vapor pressure >11.1 psia (570 mm Hg), equip with vapor recovery system or equivalent	No requirement No requirement Type of liquid, period of storage and maximum vapor pressure

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart Ka - Storage Vessels for Petroleum Liquids Constructed After May 18, 1978 Proposed/effective 5/18/78 (43 FR 21616) Promulgated 4/4/80 (45 FR 23374)	Storage tanks >40,000 gal. capacity (151,416 liters)	Volatile organic compounds (VOC)	Vapor pressure 1.5-11.1 psia (10.3-76.6 kPa), equip with floating roof or fixed roof with internal floating cover (both must meet specifications) or vapor recovery and disposal system reducing emissions at least 95%	No requirement
			Vapor pressure >11.1 psia (76.6 kPa), equip with vapor recovery and disposal system reducing emissions at least 95%	No requirement Type of liquid, period of storage, and maximum vapor pressure

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart L - Secondary Lead Smelters				
Proposed/effective 6/11/73 (38 FR 15406)	Reverberatory and blast furnaces	Particulate	0.022 gr/dscf (50 mg/dscm)	No requirement
		Opacity	20%	No requirement
Promulgated 3/8/74 (39 FR 9308)	Pot furnaces >550 lb/capacity	Opacity	10%	No requirement
Revised 4/17/74 (39 FR 13776) 10/6/75 (40 FR 46250) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				
Subpart M - Secondary Brass, Bronze, and Ingot Production Plants				
Proposed/effective 6/11/73 (38 FR 15406)	Reverberatory furnace	Particulate	0.022 gr/dscf (50 mg/dscm)	No requirement
		Opacity	20%	No requirement
Promulgated 3/8/74 (39 FR 9308)	Blast and electric furnaces	Opacity	10%	No requirement
Revised 10/6/75 (40 FR 46250) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart N - Iron and Steel Plants Proposed/effective 6/11/73 (38 FR 15406) Promulgated 3/8/74 (39 FR 9308) Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800) 4/13/78 (43 FR 15600)	Basic oxygen process furnace	Particulate Opacity	0.022 gr/dscf (50 mg/dscm) 10% (20% exception/ cycle)	No requirement No requirement Time and duration of each cycle; exhaust gas diversion; scrubber pressure loss; water supply pressure
Subpart O - Sewage Treatment Plants Proposed/effective 6/11/73 (38 FR 15406) Promulgated 3/8/74 (39 FR 9308) Revised 4/17/74 (39 FR 13776) 5/3/74 (39 FR 15396) 10/6/75 (40 FR 46250) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424)	Sludge incinerators >10% from municipal sewage treatment or >2,205 lb/day municipal sewage sludge	Particulate Opacity	1.30 lb/ton (0.65 g/kg) 20%	No requirement No requirement Mass or volume of sludge; mass of any municipal solid waste

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart P - Primary Copper Smelters				
Proposed/effective 10/16/74 (39 FR 37040)	Dryer	Particulate	0.022 gr/dscf (50 mg/dscm)	No requirement
		Opacity	20%	Continuous
Promulgated 1/15/76 (41 FR 2331)	Roaster, smelting furnace,* copper converter	SO_2	0.065%	Continuous
		Opacity	20%	No requirement
Revised 2/26/76 (41 FR 8346) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)	*Reverberatory furnaces that process high-impurity feed materials are exempt from SO_2 standard			Monthly record of charge and weight percent of arsenic, antimony, lead, and zinc
Subpart Q - Primary Zinc Smelters				
Proposed/effective 10/16/74 (39 FR 37040)	Sintering machine	Particulate	0.022 gr/dscf (50 mg/dscm)	No requirement
		Opacity	20%	Continuous
Promulgated 1/15/76 (41 FR 2331)	Roaster	SO_2	0.065%	Continuous
		Opacity	20%	No requirement
Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart R - Primary Lead Smelters				
Proposed/effective 10/16/74 (39 FR 37040)	Blast or reverberatory furnace, sintering machine discharge end	Particulate	0.022 gr/dscf (50 mg/dscm)	No requirement
		Opacity	20%	Continuous
Promulgated 1/15/76 (41 FR 2331)	Sintering machine, electric smelting furnace, converter	SO_2	0.065%	Continuous
		Opacity	20%	No requirement
Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				
Subpart S - Primary Aluminum Reduction Plants				
Proposed/effective 10/23/74 (39 FR 37730)	Potroom group	Opacity	10%	No requirement
		Total fluorides		
		(a) Soderberg	2.0-2.6 lb/ton	No requirement
Promulgated 1/26/75 (41 FR 3825)		(b) Prebake	1.9-2.5 lb/ton	No requirement
	Anode bake plants	Total fluorides	0.1 lb/ton	No requirement
Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800) 6/30/80 (45 FR 44202)		Opacity	20%	No requirement
				Daily weight, production rate of aluminum and anode, raw material feed rate, cell or potline voltages

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart T - Phosphate Fertilizer Industry Proposed/effective 10/22/74 (39 FR 37602) Promulgated 8/6/75 (40 FR 33152) Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)	Wet process phosphoric acid	Total fluorides	0.02 lb/ton	No requirement Mass flow rate, daily equivalent P_2O_5 feed, total pressure drop across scrubbing system
Subpart U - Phosphate Fertilizer Industry Proposed/effective 10/22/74 (39 FR 37602) Promulgated 8/6/75 (40 FR 33152) Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)	Superphosphoric acid	Total fluorides	0.01 lb/ton	No requirement Mass flow rate, daily equivalent P_2O_5 feed, total pressure drop across scrubbing system

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart V - Phosphate Fertilizer Industry Proposed/effective 10/24/74 (39 FR 37602) Promulgated 8/6/75 (40 FR 33152) Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)	Diammonium phosphate	Total fluorides	0.06 lb/ton	No requirement Mass flow rate, daily equivalent P_2O_5 feed, total pressure drop across scrubbing system
Subpart W - Phosphate Fertilizer Industry Proposed/effective 10/22/74 (39 FR 37602) Promulgated 8/6/75 (40 FR 33152) Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)	Triple superphosphate	Total fluorides	0.2 lb/ton	No requirement Mass flow rate, daily equivalent P_2O_5 feed, total pressure drop across scrubbing system

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart X - Phosphate Fertilizer Industry				
Proposed/effective 10/22/74 (39 FR 37602)	Granular triple superphosphate	Total fluorides	5.0×10^{-4} lb/h/ton	No requirement
Promulgated 8/6/75 (40 FR 33152)				Mass flow rate, daily equivalent P_2O_5 feed, total pressure drop across scrubbing system
Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)				
Subpart Y - Coal Preparation Plants				
Proposed/effective 10/24/74 (39 FR 37922)	Thermal dryer	Particulate	0.031 gr/dscf (0.070 g/dscm)	Temperature, Scrubber pressure loss, Water pressure
Promulgated 1/15/76 (41 FR 2232)		Opacity	20%	No requirement
Revised 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 9/7/77 (42 FR 44812) 3/3/78 (43 FR 8800)	Pneumatic coal cleaning equipment	Particulate	0.018 gr/dscf (0.040 g/dscm)	No requirement
		Opacity	10%	No requirement
	Processing and conveying equipment, storage systems, transfer and loading systems	Opacity	20%	No requirement

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart Z - Ferroalloy Production Facilities				
Proposed/effective 10/21/74 (39 FR 37470)	Electric submerged arc furnaces	Particulate	0.99 lb/MW-h (0.45 kg/MW-h) ("high silicon alloys")	No requirement
Promulgated 5/4/76 (41 FR 18497)			0.51 lb/MW-h (0.23 kg/MW-h) (chrome and manganese alloys)	
Revised 5/20/76 (41 FR 20659) 7/25/77 (42 FR 37936) 8/17/77 (42 FR 41424) 3/3/78 (43 FR 8800)			No visible emissions may escape furnace capture system	Flow rate monitoring in hood
			No visible emissions may escape tapping system for >40% of each tapping period	Flow rate monitoring in hood
		Opacity	15%	Continuous
		CO	20% volume basis	No requirement
	Dust handling equipment	Opacity	10%	No requirement

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart AA - Steel Plants				
Proposed/effective 10/21/74 (39 FR 37466)	Electric arc furnaces	Particulate	0.0052 gr/dscf (12 mg/dscm)	No requirement
		Opacity		
Promulgated 9/23/75 (40 FR 43850)		(a) control device	3%	Continuous Flow rate monitoring in capture hood, Pressure monitoring in DSE system
		(b) shop roof	0% except <20%-charging <40%-tapping	
Revised 7/25/77 (40 FR 37936) 8/17/77 (42 FR 41424) 9/7/77 (42 FR 44812) 3/3/78 (43 FR 8800)				
	Dust handling equipment	Opacity	10%	No requirement

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart BB - Kraft Pulp Mills				
Proposed/effective 9/24/76 (41 FR 42012) Promulgated 2/23/78 (43 FR 7568) Revised 8/7/78 (43 FR 34784)	Recovery furnace	Particulate	0.044 gr/dscf (0.10 g/dscm) corrected to 8% oxygen	No requirement
		Opacity	35%	Continuous
		TRS (a) straight recovery	5 ppm by volume corrected to 8% oxygen	Continuous
		(b) cross recovery	25 ppm by volume corrected to 8% oxygen	
	Smelt dissolving tank	Particulate	0.2 lb/ton (0.1 g/kg)	No requirement
		TRS	0.0168 lb/ton (0.0084 g/kg)	No requirement
	Lime kiln	Particulate (a) gaseous fuel	0.067 gr/dscf (0.15 g/dscm) corrected to 10% oxygen	No requirement
		(b) liquid fuel	0.13 gr/dscf (0.30 g/dscm) corrected to 10% oxygen	No requirement
		TRS	8 ppm by volume corrected to 10% oxygen	Continuous
	Digester, brown stack washer, evaporator, oxidation, or stripper systems	TRS	5 ppm by volume corrected to 10% oxygen*	Continuous
			*exceptions; see standards	Effluent gas incineration temperature; scrubber liquid supply pressure and gas stream pressure loss

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart DD - Grain Elevators				
Proposed/effective 8/3/78 (43 FR 34349)	Column and rack dryers	Opacity	0%	No requirement
Promulgated 8/3/78 (43 FR 34340)	Process equipment other than dryers	Particulate	0.01 gr/dscf (0.023 g/dscm)	No requirement
		Opacity	0%	No requirement
	Fugitive emissions: Truck unloading; railcar loading or unloading	Opacity	5%	No requirement
	Grain handling	Opacity	0%	No requirement
	Truck loading	Opacity	10%	No requirement
	Barge, ship loading	Opacity	20%	No requirement

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart GG - Stationary Gas Turbines	Gas turbines >10.7 GJ/h (>10 million Btu/h)	SO_2	0.015% (150 ppm) at 15% oxygen on dry basis or fuel with <0.8% sulfur	Sulfur and nitrogen content of fuel
Proposed/effective 10/3/77 (42 FR 53782)	Gas turbines >10.7 and <107.2 GJ/h (>10 million and <100 million Btu/h)*	NO_x (effective 10/3/82)	0.015% (150 ppm) at 15% oxygen on dry basis referenced to ISO standard day conditions*	
Promulgated 9/10/79 (44 FR 52792)	Gas turbines >107.2 GJ/h (100 million Btu/h)*	NO_x	0.0075% (75 ppm) at 15% oxygen on dry basis referenced to ISO standard day conditions*	
	Gas turbines >107.2 GJ/h (100 million Btu/h) used in oil/gas production or transportation not in MSA*	NO_x	0.015% (150 ppm) at 15% oxygen on dry basis referenced to ISO standard day conditions*	
	*Emergency, military (Other than garrison), military training, firefighting, and R&D turbines exempt from NO_x standards		*Adjustments allowed for thermal efficiency >25% or fuels with >0.015 nitrogen content	Continuous fuel consumption and water/fuel ratio if using NO_x control by water injection

Source category	Affected facility	Pollutant	Emission level	Monitoring requirement
Subpart HH - Lime Manufacturing Plants				
Proposed/effective 5/3/77 (42 FR 22506)	Rotary lime kiln	Particulate	0.30 lb/ton (0.15 kg/Mg)	No requirement
Promulgated 3/7/78 (43 FR 9452)		Opacity	10%	Continuous except when using wet scrubber
	Lime hydrator	Particulate	0.15 lb/ton (0.075 kg/Mg)	No requirement Mass of feed to rotary lime kiln and hydrator

SECTION III

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Title 40—PROTECTION OF ENVIRONMENT

Chapter I—Environmental Protection Agency

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES [1,1A]

Subpart A—General Provisions

Sec
60.1 Applicability.
60.2 Definitions
60.3 Units and abbreviations
60.4 Address.
60.5 Determination of construction or modification.
60.6 Review of plans.
60.7 Notification and record keeping.
60.8 Performance tests.
60.9 Availability of information.
60.10 State authority
60.11 Compliance with standards and maintenance requirements.[4]
60.12 Circumvention.[5]
60.13 Monitoring requirements.[18]
60.14 Modification [22]
60.15 Reconstruction.[22]
60.16 Priority list.[99]

Subpart B—Adoption and Submittal of State Plans for Designated Facilities [21]

60.20 Applicability.
60.21 Definitions.
60.22 Publication of guideline documents, emission guidelines, and final compliance times.
60.23 Adoption and submittal of State plans; public hearings.
60.24 Emission standards and compliance schedules.
60.25 Emission inventories, source surveillance, reports.
60.26 Legal authority.
60.27 Actions by the Administrator.
60.28 Plan revisions by the State.
60.29 Plan revisions by the Administrator.

Subpart C—Emission Guidelines and Compliance Times [73]

60.30 Scope.
60.31 Definitions.
60.32 Designated facilities
60.33 Emission guidelines.
60.34 Compliance times.

Subpart D—Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction Is Commenced After August 17, 1971 [98]

60.40 Applicability and designation of affected facility.
60.41 Definitions.
60.42 Standard for particulate matter
60.43 Standard for sulfur dioxide.
60.44 Standard for nitrogen oxides.
60.45 Emission and fuel monitoring.
60.46 Test methods and procedures

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978 [98]

60.40a Applicability and designation of affected facility.
60.41a Definitions
60.42a Standard for particulate matter
60.43a Standard for sulfur dioxide.
60.44a Standard for nitrogen oxides
60.45a Commercial demonstration permit
60.46a Compliance provisions
60.47a Emission monitoring.
60.48a Compliance determination procedures and methods.
60.49a Reporting requirements.

Subpart E—Standards of Performance for Incinerators

60.50 Applicability and designation of affected facility.
60.51 Definitions.
60.52 Standard for particulate matter
60.53 Monitoring of operations.
60.54 Test methods and procedures

Subpart F—Standards of Performance for Portland Cement Plants

60.60 Applicability and designation of affected facility.
60.61 Definitions.
60.62 Standard for particulate matter
60.63 Monitoring of operations
60.64 Test methods and procedures

Subpart G—Standards of Performance for Nitric Acid Plants

60.70 Applicability and designation of affected facility
60.71 Definitions.
60.72 Standard for nitrogen oxides.
60.73 Emission monitoring.
60.74 Test methods and procedures.

Subpart H—Standards of Performance for Sulfuric Acid Plants

60.80 Applicability and designation of affected facility.
60.81 Definitions
60.82 Standard for sulfur dioxide
60.83 Standard for acid mist
60.84 Emission monitoring
60.85 Test methods and procedures

Subpart I—Standards of Performance for Asphalt Concrete Plants [5]

60.90 Applicability and designation of affected facility
60.91 Definitions.
60.92 Standard for particulate matter.
60.93 Test methods and procedures

Subpart J—Standards of Performance for Petroleum Refineries [5]

60.100 Applicability and designation of affected facility
60.101 Definitions.
60.102 Standard for particulate matter.
60.103 Standard for carbon monoxide.
60.104 Standard for sulfur dioxide
60.105 Emission monitoring.
60.106 Test methods and procedures

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids Constructed After June 11, 1973 and Prior to May 19, 1978 [5,111]

60.110 Applicability and designation of affected facility.
60.111 Definitions.
60.112 Standard for volatile organic compounds (VOC).[111]
60.113 Monitoring of operations.

Subpart Ka—Standards of Performance for Storage vessels for Petroleum Liquids Constructed After May 18, 1978 [111]

60.110a Applicability and designation of affected facility.
60.111a Definitions.
60.112a Standard for volatile organic compounds (VOC).
60.113a Testing and procedures.
60.114a Equivalent equipment and procedures.
60.115a Monitoring of operations.

Subpart L—Standards of Performance for Secondary Lead Smelters [5]

60.120 Applicability and designation of affected facility.
60.121 Definitions
60.122 Standard for particulate matter.
60.123 Test methods and procedures.

Subpart M—Standards of Performance for Secondary Brass and Bronze Ingot Production Plants [5]

60.130 Applicability and designation of affected facility.
60.131 Definitions.
60.132 Standard for particulate matter.
60.133 Test methods and procedures.

Subpart N—Standards of Performance for Iron and Steel Plants [5]

60.140 Applicability and designation of affected facility.
60.141 Definitions.
60.142 Standard for particulate matter.
60.143 Monitoring of operations.[88]
60.144 Test methods and procedures.

Subpart O—Standards of Performance for Sewage Treatment Plants [5]

60.150 Applicability and designation of affected facility.
60.151 Definitions.
60.152 Standard for particulate matter.
60.153 Monitoring of operations
60.154 Test methods and procedures

Subpart P—Standards of Performance for Primary Copper Smelters [26]

60.160 Applicability and designation of affected facility.
60.161 Definitions.
60.162 Standard for particulate matter
60.163 Standard for sulfur dioxide.
60.164 Standard for visible emissions
60.165 Monitoring of operations
60.166 Test methods and procedures

Subpart Q—Standards of Performance for Primary Zinc Smelters[26]

60.170 Applicability and designation of affected facility.
60.171 Definitions
60.172 Standard for particulate matter.
60.173 Standard for sulfur dioxide.
60.174 Standard for visible emissions.
60.175 Monitoring of operations.
60.176 Test methods and procedures.

Subpart R—Standards of Performance for Primary Lead Smelters[26]

60.180 Applicability and designation of affected facility
60.181 Definitions.
60.182 Standard for particulate matter.
60.183 Standard for sulfur dioxide.
60.184 Standard for visible emissions.
60.185 Monitoring of operations.
60 186 Test methods and procedures.

Subpart S—Standards of Performance for Primary Aluminum Reduction Plants[27]

60.190 Applicability and designation of affected facility.
60.191 Definitions.
60.192 Standard for fluorides.
60.193 Standard for visible emissions.
60.194 Monitoring of operations.
60.195 Test methods and procedures.

Subpart T—Standards of Performance for the Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants[14]

60.200 Applicability and designation of affected facility.
60.201 Definitions.
60.202 Standard for fluorides.
60.203 Monitoring of operations.
60.204 Test methods and procedures.

Subpart U—Standards of Performance for the Phosphate Fertilizer Industry: Superphosphoric Acid Plants[14]

60.210 Applicability and designation of affected facility.
60 211 Definitions
60.212 Standard for fluorides
60.213 Monitoring of operations.
60.214 Test methods and procedures

Subpart V—Standards of Performance for the Phosphate Fertilizer Industry: Diammonium Phosphate Plants[14]

60.220 Applicability and designation of affected facility.
60.221 Definitions.
60 222 Standard for fluorides.
60.223 Monitoring of operations.
60.224 Test methods and procedures.

Subpart W—Standards of Performance for the Phosphate Fertilizer Industry: Triple Superphosphate Plants[14]

60.230 Applicability and designation of affected facility.
60.231 Definitions.
60.232 Standard for fluorides.
60.233 Monitoring of operations.
60.234 Test methods and procedures.

Subpart X—Standards of Performance for the Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities[14]

60.240 Applicability and designation of affected facility.
60.241 Definitions.
60.242 Standard for fluorides.
60.243 Monitoring of operations.
60.244 Test methods and procedures.

Subpart Y—Standards of Performance for Coal Preparation Plants[26]

60.250 Applicability and designation of affected facility.
60.251 Definitions.
60.252 Standards for particulate matter.
60.253 Monitoring of operations.
60.254 Test methods and procedures.

Subpart Z—Standards of Performance for Ferroalloy Production Facilities[33]

60.260 Applicability and designation of affected facility.
60.261 Definitions.
60.262 Standard for particulate matter.
60.263 Standard for carbon monoxide.
60.264 Emission monitoring.
60.265 Monitoring of operations.
60.266 Test methods and procedures.

Subpart AA—Standards of Performance for Steel Plants: Electric Arc Furnaces[16]

60.270 Applicability and designation of affected facility.
60.271 Definitions.
60.272 Standard for particulate matter
60 273 Emission monitoring
60.274 Monitoring of operations
60.275 Test methods and procedures

Subpart BB—Standards of Performance for Kraft Pulp Mills[82]

60.280 Applicability and designation of affected facility.
60.281 Definitions.
60.282 Standard for particulate matter.
60.283 Standard for total reduced sulfur (TRS).
60.284 Monitoring of emissions and operations.
60.285 Test methods and procedures

Subpart CC—[Reserved]

Subpart DD—Standards of Performance fo Grain Elevators[90]

60.300 Applicability and designation of affected facility.
60.301 Definitions.
60.302 Standard for particulate matter.
60.302 Test methods and procedures.
60.304 Modification.

Subpart GG—Standards of Performance for Stationary Gas Turbines[101]

60.330 Applicability and designation of affected facility.
60.331 Definitions.
60.332 Standard for nitrogen oxides.
60.333 Standard for sulfur dioxide.
60.334 Monitoring of operations.
60.335 Test methods and procedures.

Subpart HH—Standards of Performance for Lime Manufacturing Plants[85]

60.340 Applicability and designation of affected facility.
60.341 Definitions.
60.342 Standard for particulate matter.
60.343 Monitoring of emissions and operations.
60.344 Test methods and procedures.

Appendix A—Reference Methods[14]

Method 1—Sample and velocity traverses for stationary sources.
Method 2—Determination of stack gas velocity and volumetric flow rate (Type S pitot tube).
Method 3—Gas analysis for carbon dioxide, oxygen, excess air, and dry molecular weight.
Method 4—Determination of moisture content in stack gases.
Method 5—Determination of particulate emissions from stationary sources.
Method 6—Determination of sulfur dioxide emissions from stationary sources.
Method 7—Determination of nitrogen oxide emissions from stationary sources.
Method 8—Determination of sulfuric acid mist and sulfur dioxide emissions from stationary sources.
Method 9—Visual determination of the opacity of emissions from stationary sources.
Method 10—Determination of carbon monoxide emissions from stationary sources.[5]
Method 11—Determination of hydrogen sulfide content of fuel gas streams in petroleum refineries.[79]
Method 12—[Reserved]
Method 13A—Determination of total fluoride emissions from stationary sources—SPADNS Zirconium Lake Method.
Method 13B—Determination of total fluoride emissions from stationary sources—Specific Ion Electrode Method.
Method 14—Determination of fluoride emissions from potroom roof monitors of primary aluminum plants.[27]
Method 15—Determination of hydrogen sulfide, carbonyl sulfide, and carbon disulfide emissions from stationary sources.[86]
Method 16—Semicontinuous determination of sulfur emissions from stationary sources.[82]
Method 17—Determination of particulate emissions from stationary sources (in-stack filtration method).[82]
METHOD 19. DETERMINATION OF SULFUR DIOXIDE REMOVAL EFFICIENCY AND PARTICULATE, SULFUR DIOXIDE AND NITROGEN OXIDES EMISSION RATES FROM ELECTRIC UTILITY STEAM GENERATORS[98]

Method 20—Determination of Nitrogen Oxides, Sulfur Dioxide, and Oxygen Emissions from Stationary Gas Turbines[101]

Appendix B—Performance Specifications[18]

Performance Specification 1—Performance specifications and specification test procedures for transmissometer systems for continuous measurement of the opacity of stack emissions.
Performance Specification 2—Performance specifications and specification test procedures for monitors of SO_2 and NO_x from stationary sources.
Performance Specification 3—Performance specifications and specification test procedures for monitors of CO_2 and O_2 from stationary sources.

Appendix C—Determination of Emission Rate Change[22]

Appendix D—Required Emission Inventory Information[21]

AUTHORITY: Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)), unless otherwise noted.[68,83]

Subpart A—General Provisions

§ 60.1 Applicability.[8,21]

Except as provided in Subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

§ 60.2 Definitions.[102]

The terms used in this part are defined in the Act or in this section as follows:

"Act" means the Clean Air Act (42 U.S.C. 1857 et seq., as amended by Pub. L. 91-604, 84 Stat. 1676).

"Administrator" means the Administrator of the Environmental Protection Agency or his authorized representative.

"Affected facility" means, with reference to a stationary source, any apparatus to which a standard is applicable.

"Alternative method" means any method of sampling and analyzing for an air pollutant which is not a reference or equivalent method but which has been demonstrated to the Administrator's satisfaction to, in specific cases, produce results adequate for his determination of compliance.[5]

"Capital expenditure" means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable "annual asset guideline repair allowance percentage" specified in the latest edition of Internal Revenue Service (IRS) Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code. However, the total expenditure for a physical or operational change to an existing facility must not be reduced by any "excluded additions" as defined in IRS Publication 534, as would be done for tax purposes.[22,109]

"Commenced" means, with respect to the definition of "new source" in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.[5]

"Construction" means fabrication, erection, or installation of an affected facility.

"Continuous monitoring system" means the total equipment, required under the emission monitoring sections in applicable subparts, used to sample and condition (if applicable), to analyze, and to provide a permanent record of emissions or process parameters.[18]

"Equivalent method" means any method of sampling and analyzing for an air pollutant which has been demonstrated to the Administrator's satisfaction to have a consistent and quantitatively known relationship to the reference method, under specified conditions.[5]

"Existing facility" means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type.[22]

"Isokinetic sampling" means sampling in which the linear velocity of the gas entering the sampling nozzle is equal to that of the undisturbed gas stream at the sample point.

"Malfunction" means any sudden and unavoidable failure of air pollution control equipment or process equipment or of a process to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.[4]

"Modification" means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.[22]

"Monitoring device" means the total equipment, required under the monitoring of operations sections in applicable subparts, used to measure and record (if applicable) process parameters.[18]

"Nitrogen oxides" means all oxides of nitrogen except nitrous oxide, as measured by test methods set forth in this part.

"One-hour period" means any 60-minute period commencing on the hour.[4,18]

"Opacity" means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

"Owner or operator" means any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part.

"Particulate matter" means any finely divided solid or liquid material, other than uncombined water, as measured by the reference methods specified under each applicable subpart, or an equivalent or alternative method.[5,8,90]

"Proportional sampling" means sampling at a rate that produces a constant ration of sampling rate to stack gas flow rate.

"Reference method" means any method of sampling and analyzing for an air pollutant as described in Appendix A to this part.[5,8]

"Run" means the net period of time during which an emission sample is collected. Unless otherwise specified, a run may be either intermittent or continuous within the limits of good engineering practice.[5]

"Shutdown" means the cessation of operation of an affected facility for any purpose.[4]

"Six-minute period" means any one of the 10 equal parts of a one-hour period.[18]

"Standard" means a standard of performance proposed or promulgated under this part.

"Standard conditions" means a temperature of 293 K (68°F) and a pressure of 101.3 kilopascals (29.92 in Hg).[5,84]

"Startup" means the setting in operation of an affected facility for any purpose.

§ 60.3 Units and abbreviations.[5,62]

Used in this part are abbreviations and symbols of units of measure. These are defined as follows:

(a) System International (SI) units of measure:

A—ampere
g—gram
Hz—hertz
J—joule
K—degree Kelvin
kg—kilogram
m—meter
m^3—cubic meter
mg—milligram—10^{-3} gram
mm—millimeter—10^{-3} meter
Mg—megagram—10^{6} gram
mol—mole
N—newton
ng—nanogram—10^{-9} gram
nm—nanometer—10^{-9} meter
Pa—pascal
s—second
V—volt
W—watt
Ω—ohm
μg—microgram—10^{-6} gram[65]

(b) Other units of measure:

Btu—British thermal unit
°C—degree Celsius (centigrade)
cal—calorie
cfm—cubic feet per minute
cu ft—cubic feet
dcf—dry cubic feet
dcm—dry cubic meter
dscf—dry cubic feet at standard conditions
dscm—dry cubic meter at standard conditions
eq—equivalent
°F—degree Fahrenheit
ft—feet
gal—gallon
gr—grain
g-eq—gram equivalent
hr—hour
in—inch
k—1,000
l—liter
lpm—liter per minute
lb—pound
meq—milliequivalent
min—minute
ml—milliliter
mol. wt.—molecular weight
ppb—parts per billion
ppm—parts per million
psia—pounds per square inch absolute
psig—pounds per square inch gage
°R—degree Rankine
scf—cubic feet at standard conditions
scfh—cubic feet per hour at standard conditions
scm—cubic meter at standard conditions
sec—second
sq ft—square feet
std—at standard conditions

(c) Chemical nomenclature:

CdS—cadmium sulfide
CO—carbon monoxide
CO_2—carbon dioxide
HCl—hydrochloric acid
Hg—mercury
H_2O—water
H_2S—hydrogen sulfide
H_2SO_4—sulfuric acid
N_2—nitrogen
NO—nitric oxide
NO_2—nitrogen dioxide
NO_x—nitrogen oxides
O_2—oxygen
SO_2—sulfur dioxide
SO_3—sulfur trioxide
SO_x—sulfur oxides

(d) Miscellaneous:

A.S.T.M.—American Society for Testing and Materials

(Secs. 111 and 301(a) of the Clean Air Act, sec. 4(a) of Pub. L. 91-604, 84 Stat. 1683, sec 2 of Pub. L. 90-148, 81 Stat. 504 (42 U.S.C. 1857c-6, 1857g(a)))

§ 60.4 Address.[5,12]

(a) All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate and addressed to the appropriate Regional Office of the Environmental Protection Agency, to the attention of the Director, Enforcement Division. The regional offices are as follows:

Region I (Connecticut, Maine, New Hampshire, Massachusetts, Rhode Island, Vermont), John F. Kennedy Federal Building, Boston, Massachusetts 02203.

Region II (New York, New Jersey, Puerto Rico, Virgin Islands), Federal Office Building, 26 Federal Plaza (Foley Square), New York, New York 10007.

Region III (Delaware, District of Columbia, Pennsylvania, Maryland, Virginia, West Virginia), Curtis Building, Sixth and Walnut Streets, Philadelphia, Pennsylvania 19106.

Region IV (Alabama, Florida, Georgia, Mississippi, Kentucky, North Carolina, South Carolina, Tennessee), Suite 300, 1421 Peachtree Street, Atlanta, Georgia 30309

Region V (Illinois, Indiana, Minnesota, Michigan, Ohio, Wisconsin), 230 South Dearborn Street, Chicago, Illinois 60604.[59]

Region VI (Arkansas, Louisiana, New Mexico, Oklahoma, Texas), 1600 Patterson Street, Dallas, Texas 75201

Region VII (Iowa, Kansas, Missouri, Nebraska), 1735 Baltimore Street, Kansas City, Missouri 63108

Region VIII (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming), 196 Lincoln Towers, 1860 Lincoln Street, Denver, Colorado 80203

Region IX (Arizona, California, Hawaii, Nevada, Guam, American Samoa), 100 California Street, San Francisco, California 94111

Region X (Washington, Oregon, Idaho, Alaska), 1200 Sixth Avenue, Seattle, Washington 98101.

(b) Section 111(c) directs the Administrator to delegate to each State, when appropriate, the authority to implement and enforce standards of performance for new stationary sources located in such State. All information required to be submitted to EPA under paragraph (a) of this section, must also be submitted to the appropriate State Agency of any State to which this authority has been delegated (provided, that each specific delegation may except sources from a certain Federal or State reporting requirement). The appropriate mailing address for those States whose delegation request has been approved is as follows:

(A) [reserved]

(B) State of Alabama, Air Pollution Control Division, Air Pollution Control Commission, 645 S. McDonough Street, Montgomery, Alabama 36104.[45]

(C) [reserved]

(D) Arizona.

Maricopa County Department of Health Services, Bureau of Air Pollution Control, 1825 East Roosevelt Street, Phoenix, Ariz. 85006.

Pima County Health Department, Air Quality Control District, 151 West Congress, Tucson, Ariz. 85701.[51,89]

(F) California.

Bay Area Air Pollution Control District, 939 Ellis Street, San Francisco, Calif. 94 [illegible]

Del Norte County Air Pollution Control District, Courthouse, Crescent City, Calif. 95531.

Fresno County Air Pollution Control District, 515 South Cedar Avenue, Fresno, Calif. 93702

Humboldt County Air Pollution Control District, 5600 South Broadway, Eureka, Calif. 95501.

Kern County Air Pollution Control District, 1700 Flower Street (P.O. Box 997), Bakersfield, Calif. 93302.

Madera County Air Pollution Control District, 135 West Yosemite Avenue, Madera, Calif. 93637.

Mendocino County Air Pollution Control District, County Courthouse, Ukiah, Calif. 94582.

Monterey Bay Unified Air Pollution Control District, 420 Church Street (P.O. Box 487), Salinas, Calif. 93901.

Northern Sonoma County Air Pollution Control District, 3313 Chanate Road, Santa Rosa, Calif. 95404.

Sacramento County Air Pollution Control District, 3701 Branch Center Road, Sacramento, Calif. 95827.

San Diego County Air Pollution Control District, 9150 Chesapeake Drive, San Diego, Calif. 92123.

San Joaquin County Air Pollution Control District, 1601 East Hazelton Street (P.O. Box 2009), Stockton, Calif. 95201.

Santa Barbara County Air Pollution Control District, 4440 Calle Real, Santa Barbara, Calif. 93110.

Shasta County Air Pollution Control District, 1855 Placer Street, Redding, Calif. 96001.

South Coast Air Quality Management District, 9420 Telstar Avenue, El Monte, Calif. 91731.

Stanislaus County Air Pollution Control District, 820 Scenic Drive, Modesto, Calif. 95350.

Trinity County Air Pollution Control District, Box AJ, Weaverville, Calif. 96093.

Ventura County Air Pollution Control District, 625 East Santa Clara Street, Ventura, Calif. 93001.[15,17,36,40,44,48,52,89]

(G)—State of Colorado, Colorado Air Pollution Control Division, 4210 East 11th Avenue, Denver, Colorado 80220.[20]

(H) State of Connecticut, Department of Environmental Protection, State Office Building, Hartford, Connecticut 06115.[31]

(I) State of Delaware (for fossil fuel-fired steam generators; incinerators; nitric acid plants, asphalt concrete plants; storage vessels for petroleum liquids; sulfuric acid plants, and sewage treatment plants only.

Delaware Department of Natural Resources and Environmental Control, Edward Tatnall Building, Dover, Delaware 19901.[81,106]

(J)-(K) [reserved]

(L) State of Georgia, Environmental Protection Division, Department of Natural Resources, 270 Washington Street, S.W., Atlanta, Georgia 30334.[38]

(M) [Reserved]

(N) State of Idaho, Department of Health and Welfare, Statehouse, Boise, Idaho 83701.[13]

(O) [Reserved]

(P) State of Indiana, Indiana Air Pollution Control Board, 1330 West Michigan Street, Indianapolis, Indiana 46206.[46]

(Q) State of Iowa, Department of Environmental Quality, 3920 Delaware, P.O. Box 3226, Des Moines, Iowa 50316.[54]

(R)- [reserved].

(S) Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, U.S. 127, Frankfort Ky. 40601.[80]

(T) [Reserved]

(U) State of Maine, Department of Environmental Protection, State House, Augusta, Maine 04330.[24]

(V) State of Maryland: Bureau of Air Quality and Noise Control, Maryland State Department of Health and Mental Hygiene, 201 West Preston Street, Baltimore, Maryland 21201.[105]

(W) Massachusetts Department of Environmental Quality Engineering, Division of Air Quality Control, 600 Washington Street, Boston, Massachusetts 02111.[34]

(X) State of Michigan, Air Pollution Control Division, Michigan Department of Natural Resources, Stevens T. Mason Building, 8th Floor, Lansing, Michigan 48926.[25]

(Y) Minnesota Pollution Control Agency, Division of Air Quality, 1935 West County Road B-2, Roseville, Minn. 55113.[78]

(Z) [Reserved]

(AA) [reserved].

(BB) State of Montana, Department of Health and Environmental Services, Cogswell Building, Helena, Mont. 59601.[70]

(CC) Nebraska Department of Environmental Control, P.O. Box 94653, State House Station, Lincoln, Nebraska 68509[54]

(DD) Nevada.

Clark County, County District Health Department, Air Pollution Control Division, 625 Shadow Lane, Las Vegas, Nev. 89106.

Washoe County District Health Department, Division of Environmental Protection, 10 Kirman Avenue, Reno, Nev. 89502.[89]

(EE) New Hampshire Air Pollution Control Agency, Department of Health and Welfare, State Laboratory Building, Hazen Drive, Concord, New Hampshire 03301.[34]

(FF)—State of New Jersey: New Jersey Department of Environmental Protection, John Fitch Plaza, P.O. Box 2807, Trenton, New Jersey 08625.[63]

(GG) [reserved].

(HH)—New York: New York State Department of Environmental Conservation, 50 Wolf Road, New York 12233, attention: Division of Air Resources.[19]

(II) North Carolina Environmental Management Commission, Department of Natural and Economic Resources, Division of Environmental Management, P.O. Box 27687, Raleigh, North Carolina 27611 Attention: Air Quality Section[54]

(JJ)- State of North Dakota, State Department of Health, State Capitol, Bismarck North Dakota 58501[47]

(KK) Ohio—

Medina, Summit and Portage Counties; Director, Air Pollution Control, 177 South Broadway, Akron, Ohio, 44308

Stark County; Director, Air Pollution Control Division, Canton City Health Department, City Hall, 218 Cleveland Avenue SW, Canton, Ohio, 44702

Butler, Clermont, Hamilton and Warren Counties; Superintendent, Division of Air Pollution Control, 2400 Beekman Street, Cincinnati, Ohio, 45214.

Cuyahoga County; Commissioner, Division of Air Pollution Control, Department of Public Health and Welfare, 2735 Broadway Avenue, Cleveland, Ohio, 44115.

Lorain County; Control Officer, Division of Air Pollution Control, 200 West Erie Avenue, 7th Floor, Lorain, Ohio, 44052.

Belmont, Carroll, Columbiana, Harrison, Jefferson, and Monroe Counties; Director, North Ohio Valley Air Authority (NOVAA), 814 Adams Street, Steubenville, Ohio, 43952.

Clark, Darke, Greene, Miami, Montgomery, and Preble Counties; Supervisor, Regional Air Pollution Control Agency (RAPCA), Montgomery County Health Department, 451 West Third Street, Dayton, Ohio, 45402.

Lucas County and the City of Rossford (in Wood County); Director, Toledo Pollution Control Agency, 26 Main Street, Toledo, Ohio, 43605.

Adams, Brown, Lawrence, and Scioto Counties; Engineer-Director, Air Division, Portsmouth City Health Department, 740 Second Street, Portsmouth, Ohio, 45662

Allen, Ashland, Auglaize, Crawford, Defiance, Erie, Fulton, Hancock, Hardin, Henry Huron, Knox, Marion, Mercer, Morrow Ottawa, Paulding, Putnam, Richland, Sandusky, Seneca, Van Wert, Williams Wood (except City of Rossford), and Wyandot Counties; Ohio Environmental Protection Agency, Northwest District Office, 111 West Washington Street, Bowling Green, Ohio, 43402.

Ashtabula, Geauga, Lake, Mahoning, Trumbull, and Wayne Counties, Ohio Environmental Protection Agency, Northeast District Office, 2110 East Aurora Road, Twinsburg, Ohio, 44087.

Athens, Coshocton, Gallia, Guernsey, Highland, Hocking, Holmes, Jackson, Meigs Morgan, Muskingum, Noble, Perry, Pike, Ross, Tuscarawas, Vinton, and Washington Counties; Ohio Environmental Protection Agency, Southeast District Office, Route 3 Box 603, Logan, Ohio, 43138.

Champaign, Clinton, Logan, and Shelby Counties; Ohio Environmental Protection Agency, Southwest District Office, 7 East Fourth Street, Dayton, Ohio, 45402.

Delaware, Fairfield, Fayette, Franklin Licking, Madison, Pickaway, and Union Counties; Ohio Environmental Protection Agency, Central District Office, 360 East Broad Street, Columbus, Ohio, 43215[53]

(LL) [reserved].

(MM)—State of Oregon, Department of Environmental Quality, 1234 SW Morrison Street, Portland, Oregon 97205.[29]

(NN) (a) City of Philadelphia: Philadelphia Department of Public Health, Air Management Services, 801 Arch Street, Philadelphia, Pennsylvania 19107.[56]

(OO) Commonwealth of Pennsylvania: Department of Environmental Resources, Post Office Box 2063, Harrisburg, Pennsylvania 17120.[108]

(OO) State of Rhode Island, Department of Environmental Management, 83 Park Street, Providence, R.I. 02908[99]

(PP) State of South Carolina, Office of Environmental Quality Control, Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201[55]

(QQ) State of South Dakota, Department of Environmental Protection, Joe Foss Building, Pierre, South Dakota 57501.[32]

(RR) [reserved]

(SS) State of Texas, Texas Air Control Board, 8520 Shoal Creek Boulevard, Austin, Texas 78758.[95]

(TT)—State of Utah, Utah Air Conservation Committee, State Division of Health, 44 Medical Drive, Salt Lake City, Utah 84113.[37]

(UU)—State of Vermont, Agency of Environmental Protection. Box 489, Montpelier, Vermont 05602.[33]

(VV) Commonwealth of Virginia Virginia State Air Pollution Control Board Room 1106, Ninth Street Office Building Richmond, Virginia 23219.[30]

(WW) (i) Washington: State of Washington, Department of Ecology, Olympia, Washington 98504.

(ii) Northwest Air Pollution Authority, 207 Pioneer Building, Second and Pine Streets, Mount Vernon, Washington 98273.

(iii) Puget Sound Air Pollution Control Agency, 410 West Harrison Street, Seattle, Washington 98119.

(iv) Spokane County Air Pollution Control Authority, North 811 Jefferson, Spokane, Washington 99201.

(v) Southwest Air Pollution Control Authority, Suite 7601 H, NE Hazel Dell Avenue, Vancouver, Washington 98665.[12,28]

(vi) Olympic Air Pollution Control Authority, 120 East State Avenue, Olympia, WA 98501.[97]

(XX) [reserved].

(YY) Wisconsin—

Wisconsin Department of Natural Resources, P.O. Box 7921, Madison, Wisconsin 53707.[5]

(ZZ) State of Wyoming, Air Quality Division of the Department of Environmental Quality, Hathaway Building, Cheyenne, Wyo. 82002.[72]

(AAA) [reserved]

(BBB)—Commonwealth of Puerto Rico Commonwealth of Puerto Rico Environmental Quality Board, P.O Box 11785 Santurce, P.R 00910[77]

(CCC)—U.S. Virgin Islands: U.S. Virgin Islands Department of Conservation and Cultural Affairs, P.O. Box 578, Charlotte Amalie, St. Thomas, U.S. Virgin Islands 00801.[41]

(DDD) [reserved]

§ 60.5 Determination of construction or modification. [22]

(a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.

(b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

§ 60.6 Review of plans.

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.

(b) (1) A separate request shall be submitted for each construction or modification project. [5]

(2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any requipment to be used for measurement or control of emissions. [5]

(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall (1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or (2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

§ 60.7 Notification and record keeping.

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification as follows:

(1) A notification of the date construction (or reconstruction as defined under § 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form. [22]

(2) A notification of the anticipated date of initial startup of an affected facility postmarked not more than 60 days nor less than 30 days prior to such date. [22]

(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date. [22]

(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in § 60.14(e) [109] This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice. [22]

(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with § 60.13(c). Notification shall be postmarked not less than 30 days prior to such date. [18]

(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative. [18]

(c) Each owner or operator required to install a continuous monitoring system shall submit a written report of excess emissions (as defined in applicable subparts) to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter and shall include the following information: [18]

(1) The magnitude of excess emissions computed in accordance with § 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. [18]

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted. [18]

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments. [18]

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report. [4, 18]

(d) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations, all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records. [5, 18]

(e) If notification substantially similar to that in paragraph (a) of this section is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section. [22]

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

§ 60.8 Performance tests.

(a) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, or (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act. [5]

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard. [4, 74]

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. [5, 98]

(e) The owner or operator of an affected facility shall provide, or cause to

be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).

(4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.[5,98]

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68,83]

§ 60.9 Availability of information.

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this Part shall be governed by Part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§ 60.5 and 60.6 is governed by § 2.201 through § 2.213 of this chapter and not by § 2.301 of this chapter.)

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68,83]

§ 60.10 State authority.

The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from:

(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

(Sec. 116 of the Clean Air Act as amended (42 U.S.C. 7416)).[68,83]

§ 60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined only by performance tests established by § 60.8, unless otherwise specified in the applicable standard.[111]

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Reference Method 9 in Appendix A of this part or any alternative method that is approved by the Administrator. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in Appendix B of this part, has been properly maintained and (at the time of the alleged violation) calibrated, and that the resulting data have not been tampered with in any way.[10,60]

(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(e)(1) An owner or operator of an affected facility may request the Administrator to determine opacity of emissions from the affected facility during the initial performance tests required by § 60.8.[10]

(2) Upon receipt from such owner or operator of the written report of the results of the performance tests required by § 60.8, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with § 60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, he shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.[10]

(3) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.[10]

(4) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the FEDERAL REGISTER.[10]

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68,83]

§ 60.12 Circumvention.[5]

No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

§ 60.13 Monitoring requirements.[18]

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring system under Appendix B to this part, unless:[82]

(1) The continuous monitoring system is subject to the provisions of paragraphs (c)(2) and (c)(3) of this section, or[82]

(2) otherwise specified in an applicable subpart or by the Administrator.[82]

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under § 60.8. Verification of operational status shall, as a minimum, consist of the following:

(1) For continuous monitoring systems referenced in paragraph (c)(1) of this section, completion of the conditioning period specified by applicable requirements in Appendix B.

(2) For continuous monitoring systems referenced in paragraph (c)(2) of this section, completion of seven days of operation.

(3) For monitoring devices referenced in applicable subparts, completion of the manufacturer's written requirements or recommendations for checking the operation or calibration of the device.

(c) During any performance tests required under § 60.8 or within 30 days thereafter and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of any affected facility shall conduct continuous monitoring system performance evaluations and furnish the Administrator within 60 days thereof two or, upon request, more copies of a written report of the results of such tests. These continuous monitoring system performance evaluations shall be conducted in accordance with the following specifications and procedures:

(1) Continuous monitoring systems listed within this paragraph except as provided in paragraph (c)(2) of this section shall be evaluated in accordance with the requirements and procedures contained in the applicable performance specification of Appendix B as follows:

(i) Continuous monitoring systems for measuring opacity of emissions shall comply with Performance Specification 1.

(ii) Continuous monitoring systems for measuring nitrogen oxides emissions shall comply with Performance Specification 2.

(iii) Continuous monitoring systems for measuring sulfur dioxide emissions shall comply with Performance Specification 2.

(iv) Continuous monitoring systems for measuring the oxygen content or carbon dioxide content of effluent gases shall comply with Performance Specification 3.

(2) An owner or operator who, prior to September 11, 1974, entered into a binding contractual obligation to purchase specific continuous monitoring system components except as referenced by paragraph (c)(2)(iii) of this section shall comply with the following requirements:

(i) Continuous monitoring systems for measuring opacity of emissions shall be capable of measuring emission levels within ±20 percent with a confidence level of 95 percent. The Calibration Error Test and associated calculation procedures set forth in Performance Specification 1 of Appendix B shall be used for demonstrating compliance with this specification.

(ii) Continuous monitoring systems for measurement of nitrogen oxides or sulfur dioxide shall be capable of measuring emission levels within ±20 percent with a confidence level of 95 percent. The Calibration Error Test, the Field Test for Accuracy (Relative), and associated operating and calculation procedures set forth in Performance Specification 2 of Appendix B shall be used for demonstrating compliance with this specification.

(iii) Owners or operators of all continuous monitoring systems installed on an affected facility prior to October 6, 1975 are not required to conduct tests under paragraphs (c)(2)(i) and/or (ii) of this section unless requested by the Administrator.[23]

(3) All continuous monitoring systems referenced by paragraph (c)(2) of this section shall be upgraded or replaced (if necessary) with new continuous monitoring systems, and the new or improved systems shall be demonstrated to comply with applicable performance specifications under paragraph (c)(1) of this section on or before September 11, 1979.[57]

(d) Owners or operators of all continuous monitoring systems installed in accordance with the provisions of this part shall check the zero and span drift at least once daily in accordance with the method prescribed by the manufacturer of such systems unless the manufacturer recommends adjustments at shorter intervals, in which case such recommendations shall be followed. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour calibration drift limits of the applicable performance specifications in Appendix B are exceeded. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero or span drift adjustments except that for systems using automatic zero adjustments, the optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds four percent opacity. Unless otherwise approved by the Administrator, the following procedures, as applicable, shall be followed:

(1) For extractive continuous monitoring systems measuring gases, minimum procedures shall include introducing applicable zero and span gas mixtures into the measurement system as near the probe as is practical. Span and zero gases certified by their manufacturer to be traceable to National Bureau of Standards reference gases shall be used whenever these reference gases are available. The span and zero gas mixtures shall be the same composition as specified in Appendix B of this part. Every six months from date of manufacture, span and zero gases shall be reanalyzed by conducting triplicate analyses with Reference Methods 6 for SO_2, 7 for NO_x, and 3 for O_2 and CO_2, respectively. The gases may be analyzed at less frequent intervals if longer shelf lives are guaranteed by the manufacturer.

(2) For non-extractive continuous monitoring systems measuring gases, minimum procedures shall include upscale check(s) using a certified calibration gas cell or test cell which is functionally equivalent to a known gas concentration. The zero check may be performed by computing the zero value from upscale measurements or by mechanically producing a zero condition.

(3) For continuous monitoring systems measuring opacity of emissions, minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under paragraph (d) of this section, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by paragraphs (c)(1) and (c)(2) of this section for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive ten-second period and one cycle of data recording for each successive six-minute period.[57]

(2) All continuous monitoring systems referenced by paragraph (c)(1) of this section for measuring oxides of nitrogen, sulfur dioxide, carbon dioxide, or oxygen shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(3) All continuous monitoring systems referenced by paragraph (c)(2) of this section, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive one-hour period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of Appendix B of this part shall be used.

(g) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install applicable continuous monitoring systems on each separate effluent unless

the installation of fewer systems is approved by the Administrator.

(h) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to six-minute averages and for systems other than opacity to one-hour averages for time periods under § 60.2 (x) and (r) respectively. Six-minute opacity averages shall be calculated from 24 or more data points equally spaced over each six-minute period. For systems other than opacity, one-hour averages shall be computed from four or more data points equally spaced over each one-hour period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data output of all continuous monitoring systems may be recorded in reduced or nonreduced form (e.g. ppm pollutant and percent O_2 or lb/million Btu of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in subparts to specify the applicable standard (e.g., rounded to the nearest one percent opacity).

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following: [42]

(1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances with the effluent gases.

(2) Alternative monitoring requirements when the affected facility is infrequently operated.

(3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(5) Alternative methods of converting pollutant concentration measurements to units of the standards.

(6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

(8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, Appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities are released to the atmosphere through more than one point.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

§ 60.14 Modification. [22]

(a) Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere. [109]

(b) Emission rate shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors," EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrate that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in paragraph (b)(1) of this section does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in paragraph (b)(1) of this section. When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in Appendix C of this part shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

(d) [Reserved] [109]

(e) The following shall not, by themselves, be considered modifications under this part:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of paragraph (c) of this section and § 60.15.

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility. [90]

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by § 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification. [109]

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in paragraph (a) of this section, compliance with all applicable standards must be achieved. [109]

§ 60.15 Reconstruction.[22]

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost" means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by paragraph (d) of this section and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under paragraph (e) shall be based on:

(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;

(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;

(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and

(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

§ 60.16 Priority list.[99]

Prioritized Major Source Categories

*Priority Number**

Source Category

1. Synthetic Organic Chemical Manufacturing
   (a) Unit processes
   (b) Storage and handling equipment
   (c) Fugitive emission sources
   (d) Secondary sources
2. Industrial Surface Coating: Cans
3. Petroleum Refineries: Fugitive Sources
4. Industrial Surface Coating: Paper
5. Dry Cleaning
   (a) Perchloroethylene
   (b) Petroleum solvent
6. Graphic Arts
7. Polymers and Resins: Acrylic Resins
8. Mineral Wool
9. Stationary Internal Combustion Engines
10. Industrial Surface Coating: Fabric
11. Fossil-Fuel-Fired Steam Generators
    Industrial Boilers
12. Incineration: Non-Municipal
13. Non-Metallic Mineral Processing
14. Metallic Mineral Processing
15. Secondary Copper
16. Phosphate Rock Preparation
17. Foundries: Steel and Gray Iron
18. Polymers and Resins: Polyethylene
19. Charcoal Production
20. Synthetic Rubber
    (a) Tire manufacture
    (b) SBR production
21. Vegetable Oil
22. Industrial Surface Coating: Metal Coil
23. Petroleum Transportation and Marketing
24. By-Product Coke Ovens
25. Synthetic Fibers
26. Plywood Manufacture
27. Industrial Surface Coating: Automobiles
28. Industrial Surface Coating: Large
    Appliances
29. Crude Oil and Natural Gas Production
30. Secondary Aluminum
31. Potash
32. Sintering: Clay and Fly Ash
33. Glass
34. Gypsum
35. Sodium Carbonate
36. Secondary Zinc
37. Polymers and Resins: Phenolic
38. Polymers and Resins: Urea—Melamine
39. Ammonia
40. Polymers and Resins: Polystyrene
41. Polymers and Resins: ABS–SAN Resins
42. Fiberglass
43. Polymers and Resins: Polypropylene
44. Textile Processing
45. Asphalt Roofing Plants
46. Brick and Related Clay Products
47. Ceramic Clay Manufacturing
48. Ammonium Nitrate Fertilizer
49. Castable Refractories
50. Borax and Boric Acid
51. Polymers and Resins. Polyester Resins
52. Ammonium Sulfate
53. Starch
54. Perlite
55. Phosphoric Acid: Thermal Process
56. Uranium Refining
57. Animal Feed Defluorination
58. Urea (for fertilizer and polymers)
59. Detergent

Other Source Categories

Lead acid battery manufacture**
Organic solvent cleaning**
Industrial surface coating: metal furniture**
Stationary gas turbines***

(Sec. 111, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7601))

---

* Low numbers have highest priority; e.g., N high priority, No. 59 is low priority.

** Minor source category, but included on list since an NSPS is being developed for that source category

*** Not prioritized, since an NSPS for this major source category has already been proposed.

Subpart B—Adoption and Submittal of State Plans for Designated Facilities[21]

§ 60.20 Applicability.

The provisions of this subpart apply to States upon publication of a final guideline document under § 60.22(a).

§ 60.21 Definitions.

Terms used but not defined in this subpart shall have the meaning given them in the Act and in subpart A:

(a) "Designated pollutant" means any air pollutant, emissions of which are subject to a standard of performance for new stationary sources but for which air quality criteria have not been issued, and which is not included on a list published under section 108(a) or section 112(b)(1)(A) of the Act.

(b) "Designated facility" means any existing facility (see § 60.2(aa)) which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility (see § 60.2(e)).

(c) "Plan" means a plan under section 111(d) of the Act which establishes emission standards for designated pollutants from designated facilities and provides for the implementation and enforcement of such emission standards.

(d) "Applicable plan" means the plan, or most recent revision thereof, which has been approved under § 60.27(b) or promulgated under § 60.27(d).

(e) "Emission guideline" means a guideline set forth in subpart C of this part, or in a final guideline document published under § 60.22(a), which reflects the degree of emission reduction achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated for designated facilities.

(f) "Emission standard" means a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, or prescribing equipment specifications for control of air pollution emissions.

(g) "Compliance schedule" means a legally enforceable schedule specifying a date or dates by which a source or category or sources must comply with specific emission standards contained in a plan or with any increments of progress to achieve such compliance.

(h) "Increments of progress" means steps to achieve compliance which must be taken by an owner or operator of a designated facility, including:

(1) Submittal of a final control plan for the designated facility to the appropriate air pollution control agency;

(2) Awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification.

(3) Initiation of on-site construction or installation of emission control equipment or process change;

(4) Completion of on-site construction or installation of emission control equipment or process change; and

(5) Final compliance.

(i) "Region" means an air quality control region designated under section 107 of the Act and described in Part 81 of this chapter.

(j) "Local agency" means any local governmental agency.

§ 60.22 Publication of guideline documents, emission guidelines, and final compliance times.

(a) After promulgation of a standard of performance for the control of a designated pollutant from affected facilities, the Administrator will publish a draft guideline document containing information pertinent to control of the designated pollutant from designated facilities. Notice of the availability of the draft guideline document will be published in the FEDERAL REGISTER, and public comments on its contents will be invited. After consideration of public comments, a final guideline document will be published and notice of its availability will be published in the FEDERAL REGISTER.

(b) Guideline documents published under this section will provide information for the development of State plans, such as:

(1) Information concerning known or suspected endangerment of public health or welfare caused, or contributed to, by the designated pollutant.

(2) A description of systems of emission reduction which, in the judgment of the Administrator, have been adequately demonstrated.

(3) Information on the degree of emission reduction which is achievable with each system, together with information on the costs and environmental effects of applying each system to designated facilities.

(4) Incremental periods of time normally expected to be necessary for the design, installation, and startup of identified control systems.

(5) An emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved. The Administrator will specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.

(6) Such other available information as the Administrator determines may contribute to the formulation of State plans.

(c) Except as provided in paragraph (d)(1) of this section, the emission guidelines and compliance times referred to in paragraph (b)(5) of this section will be proposed for comment upon publication of the draft guideline document, and after consideration of comments will be promulgated in Subpart C of this part with such modifications as may be appropriate.

(d)(1) If the Administrator determines that a designated pollutant may cause or contribute to endangerment of public welfare, but that adverse effects on public health have not been demonstrated, he will include the determination in the draft guideline document and in the FEDERAL REGISTER notice of its availability. Except as provided in paragraph (d)(2) of this section, paragraph (c) of this section shall be inapplicable in such cases.

(2) If the Administrator determines at any time on the basis of new information that a prior determination under paragraph (d)(1) of this section is incorrect or no longer correct, he will publish notice of the determination in the FEDERAL REGISTER, revise the guideline document as necessary under paragraph (a) of this section, and propose and promulgate emission guidelines and compliance times under paragraph (c) of this section.

§ 60.23 Adoption and submittal of State plans; public hearings.

(a)(1) Within nine months after notice of the availability of a final guideline document is published under § 60.22(a), each State shall adopt and submit to the Administrator, in accordance with § 60.4, a plan for the control of the designated pollutant to which the guideline document applies.

(2) Within nine months after notice of the availability of a final revised guideline document is published as provided in § 60.22(d)(2), each State shall adopt and submit to the Administrator any plan revision necessary to meet the requirements of this subpart.

(b) If no designated facility is located within a State, the State shall submit a letter of certification to that effect to the Administrator within the time specified in paragraph (a) of this section. Such certification shall exempt the State from the requirements of this subpart for that designated pollutant.

(c)(1) Except as provided in paragraphs (c)(2) and (c)(3) of this section, the State shall, prior to the adoption of any plan or revision thereof, conduct one or more public hearings within the State on such plan or plan revision.

(2) No hearing shall be required for any change to an increment of progress in an approved compliance schedule unless the change is likely to cause the facility to be unable to comply with the final compliance date in the schedule.

(3) No hearing shall be required on an emission standard in effect prior to the effective date of this subpart if it was adopted after a public hearing and is at least as stringent as the corresponding emission guideline specified in the applicable guideline document published under § 60.22(a).

(d) Any hearing required by paragraph (c) of this section shall be held only after reasonable notice. Notice shall be given at least 30 days prior to the date of such hearing and shall include:

(1) Notification to the public by prominently advertising the date, time, and place of such hearing in each region affected;

(2) Availability, at the time of public announcement, of each proposed plan or

revision thereof for public inspection in at least one location in each region to which it will apply;

(3) Notification to the Administrator;

(4) Notification to each local air pollution control agency in each region to which the plan or revision will apply; and

(5) In the case of an interstate region, notification to any other State included in the region.

(e) The State shall prepare and retain, for a minimum of 2 years, a record of each hearing for inspection by any interested party. The record shall contain, as a minimum, a list of witnesses together with the text of each presentation.

(f) The State shall submit with the plan or revision:

(1) Certification that each hearing required by paragraph (c) of this section was held in accordance with the notice required by paragraph (d) of this section; and

(2) A list of witnesses and their organizational affiliations, if any, appearing at the hearing and a brief written summary of each presentation or written submission.

(g) Upon written application by a State agency (through the appropriate Regional Office), the Administrator may approve State procedures designed to insure public participation in the matters for which hearings are required and public notification of the opportunity to participate if, in the judgment of the Administrator, the procedures, although different from the requirements of this subpart, in fact provide for adequate notice to and participation of the public. The Administrator may impose such conditions on his approval as he deems necessary. Procedures approved under this section shall be deemed to satisfy the requirements of this subpart regarding procedures for public hearings.

§ 60.24 Emission standards and compliance schedules.

(a) Each plan shall include emission standards and compliance schedules.

(b)(1) Emission standards shall prescribe allowable rates of emissions except when it is clearly impracticable. Such cases will be identified in the guideline documents issued under § 60.22. Where emission standards prescribing equipment specifications are established, the plan shall, to the degree possible, set forth the emission reductions achievable by implementation of such specifications, and may permit compliance by the use of equipment determined by the State to be equivalent to that prescribed.

(2) Test methods and procedures for determining compliance with the emission standards shall be specified in the plan. Methods other than those specified in Appendix A to this part may be specified in the plan if shown to be equivalent or alternative methods as defined in § 60.2 (t) and (u).

(3) Emission standards shall apply to all designated facilities within the State. A plan may contain emission standards adopted by local jurisdictions provided that the standards are enforceable by the State.

(c) Except as provided in paragraph (f) of this section, where the Administrator has determined that a designated pollutant may cause or contribute to endangerment of public health, emission standards shall be no less stringent than the corresponding emission guideline(s) specified in Subpart C of this part, and final compliance shall be required as expeditiously as practicable but no later than the compliance times specified in Subpart C of this part.

(d) Where the Administrator has determined that a designated pollutant may cause or contribute to endangerment of public welfare but that adverse effects on public health have not been demonstrated, States may balance the emission guidelines, compliance times, and other information provided in the applicable guideline document against other factors of public concern in establishing emission standards, compliance schedules, and variances. Appropriate consideration shall be given to the factors specified in § 60.22(b) and to information presented at the public hearing(s) conducted under § 60.23(c).

(e) (1) Any compliance schedule extending more than 12 months from the date required for submittal of the plan shall include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities. Increments of progress shall include, where practicable, each increment of progress specified in § 60.21(h) and shall include such additional increments of progress as may be necessary to permit close and effective supervision of progress toward final compliance.

(2) A plan may provide that compliance schedules for individual sources or categories of sources will be formulated after plan submittal. Any such schedule shall be the subject of a public hearing held according to § 60.23 and shall be submitted to the Administrator within 60 days after the date of adoption of the schedule but in no case later than the date prescribed for submittal of the first semiannual report required by § 60.25(e).

(f) On a case-by-case basis for particular designated facilities, or classes of facilities, States may provide for the application of less stringent emission standards or longer compliance schedules than those otherwise required by paragraph (c) of this section, provided that the State demonstrates with respect to each such facility (or class of facilities):

(1) Unreasonable cost of control resulting from plant age, location, or basic process design;

(2) Physical impossibility of installing necessary control equipment; or

(3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

(g) Nothing in this subpart shall be construed to preclude any State or political subdivision thereof from adopting or enforcing (1) emission standards more stringent than emission guidelines specified in Subpart C of this part or in applicable guideline documents or (2) compliance schedules requiring final compliance at earlier times than those specified in Subpart C or in applicable guideline documents.

(Sec. 116 of the Clean Air Act as amended (42 U.S.C. 7416)). 68, 83

§ 60.25 Emission inventories, source surveillance, reports.

(a) Each plan shall include an inventory of all designated facilities, including emission data for the designated pollutants and information related to emissions as specified in Appendix D to this part. Such data shall be summarized in the plan, and emission rates of designated pollutants from designated facilities shall be correlated with applicable emission standards. As used in this subpart, "correlated" means presented in such a manner as to show the relationship between measured or estimated amounts of emissions and the amounts of such emissions allowable under applicable emission standards.

(b) Each plan shall provide for monitoring the status of compliance with applicable emission standards. Each plan shall, as a minimum, provide for:

(1) Legally enforceable procedures for requiring owners or operators of designated facilities to maintain records and periodically report to the State information on the nature and amount of emissions from such facilities, and/or such other information as may be necessary to enable the State to determine whether such facilities are in compliance with applicable portions of the plan.

(2) Periodic inspection and, when applicable, testing of designated facilities.

(c) Each plan shall provide that information obtained by the State under paragraph (b) of this section shall be correlated with applicable emission standards (see § 60.25(a)) and made available to the general public.

(d) The provisions referred to in paragraphs (b) and (c) of this section shall be specifically identified. Copies of such provisions shall be submitted with the plan unless:

(1) They have been approved as portions of a preceding plan submitted under this subpart or as portions of an implementation plan submitted under section 110 of the Act, and

(2) The State demonstrates:

(i) That the provisions are applicable to the designated pollutant(s) for which the plan is submitted, and

(ii) That the requirements of § 60.26 are met

(e) The State shall submit reports on progress in plan enforcement to the Administrator on an annual (calendar year) basis, commencing with the first full report period after approval of a plan or after promulgation of a plan by the Administrator. Information required under this paragraph must be included in the annual report required by § 51.321 of this chapter.[104]

(f) Each progress report shall include:

(1) Enforcement actions initiated against designated facilities during the reporting period, under any emission

standard or compliance schedule of the plan.

(2) Identification of the achievement of any increment of progress required by the applicable plan during the reporting period.

(3) Identification of designated facilities that have ceased operation during the reporting period.

(4) Submission of emission inventory data as described in paragraph (a) of this section for designated facilities that were not in operation at the time of plan development but began operation during the reporting period.

(5) Submission of additional data as necessary to update the information submitted under paragraph (a) of this section or in previous progress reports.

(6) Submission of copies of technical reports on all performance testing on designated facilities conducted under paragraph (b)(2) of this section, complete with concurrently recorded process data.

§ 60.26 *Legal authority.*

(a) Each plan shall show that the State has legal authority to carry out the plan, including authority to:

(1) Adopt emission standards and compliance schedules applicable to designated facilities.

(2) Enforce applicable laws, regulations, standards, and compliance schedules, and seek injunctive relief.

(3) Obtain information necessary to determine whether designated facilities are in compliance with applicable laws, regulations, standards, and compliance schedules, including authority to require recordkeeping and to make inspections and conduct tests of designated facilities.

(4) Require owners or operators of designated facilities to install, maintain, and use emission monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such facilities; also authority for the State to make such data available to the public as reported and as correlated with applicable emission standards.

(b) The provisions of law or regulations which the State determines provide the authorities required by this section shall be specifically identified. Copies of such laws or regulations shall be submitted with the plan unless:

(1) They have been approved as portions of a preceding plan submitted under this subpart or as portions of an implementation plan submitted under section 110 of the Act, and

(2) The State demonstrates that the laws or regulations are applicable to the designated pollutant(s) for which the plan is submitted.

(c) The plan shall show that the legal authorities specified in this section are available to the State at the time of submission of the plan. Legal authority adequate to meet the requirements of paragraphs (a)(3) and (4) of this section may be delegated to the State under section 114 of the Act.

(d) A State governmental agency other than the State air pollution control agency may be assigned responsibility for carrying out a portion of a plan if the plan demonstrates to the Administrator's satisfaction that the State governmental agency has the legal authority necessary to carry out that portion of the plan.

(e) The State may authorize a local agency to carry out a plan, or portion thereof, within the local agency's jurisdiction if the plan demonstrates to the Administrator's satisfaction that the local agency has the legal authority necessary to implement the plan or portion thereof, and that the authorization does not relieve the State of responsibility under the Act for carrying out the plan or portion thereof.

§ 60.27 Actions by the Administrator.

(a) The Administrator may, whenever he determines necessary, extend the period for submission of any plan or plan revision or portion thereof.

(b) After receipt of a plan or plan revision, the Administrator will propose the plan or revision for approval or disapproval. The Administrator will, within four months after the date required for submission of a plan or plan revision, approve or disapprove such plan or revision or each portion thereof.

(c) The Administrator will, after consideration of any State hearing record, promptly prepare and publish proposed regulations setting forth a plan, or portion thereof, for a State if:

(1) The State fails to submit a plan within the time prescribed;

(2) The State fails to submit a plan revision required by § 60.23(a)(2) within the time prescribed; or

(3) The Administrator disapproves the State plan or plan revision or any portion thereof, as unsatisfactory because the requirements of this subpart have not been met.

(d) The Administrator will, within six months after the date required for submission of a plan or plan revision, promulgate the regulations proposed under paragraph (c) of this section with such modifications as may be appropriate unless, prior to such promulgation, the State has adopted and submitted a plan or plan revision which the Administrator determines to be approvable.

(e)(1) Except as provided in paragraph (e)(2) of this section, regulations proposed and promulgated by the Administrator under this section will prescribe emission standards of the same stringency as the corresponding emission guideline(s) specified in the final guideline document published under § 60.22(a) and will require final compliance with such standards as expeditiously as practicable but no later than the times specified in the guideline document.

(2) Upon application by the owner or operator of a designated facility to which regulations proposed and promulgated under this section will apply, the Administrator may provide for the application of less stringent emission standards or longer compliance schedules than those otherwise required by this section in accordance with the criteria specified in § 60.24(f).

(f) If a State failed to hold a public hearing as required by § 60.23(c), the Administrator will provide opportunity for a hearing within the State prior to promulgation of a plan under paragraph (d) of this section.

§ 60.28 Plan revisions by the State.

(a) Plan revisions which have the effect of delaying compliance with applicable emission standards or increments of progress or of establishing less stringent emission standards shall be submitted to the Administrator within 60 days after adoption in accordance with the procedures and requirements applicable to development and submission of the original plan.

(b) More stringent emission standards, or orders which have the effect of accelerating compliance, may be submitted to the Administrator as plan revisions in accordance with the procedures and requirements applicable to development and submission of the original plan.

(c) A revision of a plan, or any portion thereof, shall not be considered part of an applicable plan until approved by the Administrator in accordance with this subpart.

§ 60.29 Plan revisions by the Administrator.

After notice and opportunity for public hearing in each affected State, the Administrator may revise any provision of an applicable plan if:

(a) The provision was promulgated by the Administrator, and

(b) The plan, as revised, will be consistent with the Act and with the requirements of this subpart.

Subpart C—Emission Guidelines and Compliance Times[73]

§ 60.30 Scope.

This subpart contains emission guidelines and compliance times for the control of certain designated pollutants from certain designated facilities in accordance with section 111(d) of the Act and Subpart B.

§ 60.31 Definitions.

Terms used but not defined in this subpart have the meaning given them in the Act and in Subparts A and B of this part.

§ 60.32 Designated facilities.

(a) Sulfuric acid production units. The designated facility to which §§ 60.33 (a) and 60.34(a) apply is each existing "sulfuric acid production unit" as defined in § 60.81(a) of Subpart H.

§ 60.33 Emission guidelines.

(a) Sulfuric acid production units. The emission guideline for designated facilities is 0.25 gram sulfuric acid mist (as measured by Reference Method 8, of Appendix A) per kilogram of sulfuric acid produced (0.5 lb/ton), the production being expressed as 100 percent H_2SO_4.

§ 60.34 Compliance times.

(a) Sulfuric acid production units. Planning, awarding of contracts, and installation of equipment capable of attaining the level of the emission guideline established under § 60.33(a) can be accomplished within 17 months after the effective date of a State emission standard for sulfuric acid mist.

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971[98,110]

§ 60.40 Applicability and designation of affected facility.[8,49,64,94]

(a) The affected facilities to which the provisions of this subpart apply are:

(1) Each fossil-fuel-fired steam generating unit of more than 73 megawatts heat input rate (250 million Btu per hour).

(2) Each fossil-fuel and wood-residue-fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 megawatts (250 million Btu per hour).

(b) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.

(c) Except as provided in paragraph (d) of this section, any facility under paragraph (a) of this section that commenced construction or modification after August 17, 1971, is subject to the requirements of this subpart.[84]

(d) The requirements of §§ 60.44(a)(4), (a)(5), (b) and (d), and 60.45(f)(4)(vi) are applicable to lignite-fired steam generating units that commenced construction or modification after December 22, 1976.[84]

(e) Any facility covered under Subpart Da is not covered under this Subpart.[98]

§ 60.41 Definitions.[8]

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, and in Subpart A of this part.

(a) "Fossil-fuel fired steam generating unit" means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.

(b) "Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

(c) "Coal refuse" means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.[11]

(d) "Fossil fuel and wood residue-fired steam generating unit" means a furnace or boiler used in the process of burning fossil fuel and wood residue for the purpose of producing steam by heat transfer.[49]

(e) "Wood residue" means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.[49]

(f) "Coal" means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society for Testing Material. Designation D 388-66.[84]

§ 60.42 Standard for particulate matter.[8]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which:

(1) Contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel or fossil fuel and wood residue.[49]

(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.[18,76]

(b)(1) On and after (the date of publication of this amendment), no owner or operator shall cause to be discharged into the atmosphere from the Southwestern Public Service Company's Harrington Station Unit #1, in Amarillo, Texas, any gases which exhibit greater than 35% opacity, except that a maximum of 42% opacity shall be permitted for not more than 6 minutes in any hour.[107]

(2) Interstate Power Company shall not cause to be discharged into the atmosphere from its Lansing Station Unit No. 1 in Lansing, Iowa, any gases which exhibit greater than 32% opacity, except that a maximum of 39% opacity shall be permitted for not more than six minutes in any hour.[112]

(Sec. 111.301(a), Clear Air Act as amended (42 U.S.C. 7411, 7601)).

§ 60.43 Standard for sulfur dioxide.[2,8]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of:

(1) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.[49]

(2) 520 nanograms per joule heat input (1.2 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue.[49]

(b) When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{so_2} = [y(340) + z(520)]/y + z$$

where:

PS_{so_2} is the prorated standard for sulfur dioxide when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired,

y is the percentage of total heat input derived from liquid fossil fuel, and

z is the percentage of total heat input derived from solid fossil fuel.[49]

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

§ 60.44 Standard for nitrogen oxides.[8]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:

(1) 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel or gaseous fossil fuel and wood residue.[49]

(2) 130 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.[49]

(3) 300 nanograms per joule heat input (0.70 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).[11,49]

(4) 260 nanograms per joule heat input (0.60 lb per million Btu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).[84]

(5) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.[84]

(b) Except as provided under paragraphs (c) and (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NO_x} = \frac{w(260) + x(86) + y(130) + z(300)}{w + x + y + z}$$

where:

PS_{NO_x} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;

w = is the percentage of total heat input

derived from lignite;

x=is the percentage of total heat input derived from gaseous fossil fuel;

y=is the percentage of total heat input derived from liquid fossil fuel; and

z=is the percentage of total heat input derived from solid fossil fuel (except lignite). [11,49,84]

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for nitrogen oxides does not apply.[84]

(d) Cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota, South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel combusted in combination with that lignite.[84]

§ 60.45 Emission and fuel monitoring.[4,8,18]

(a) Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, and either oxygen or carbon dioxide except as provided in paragraph (b) of this section.[57]

(b) Certain of the continuous monitoring system requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:[57]

(1) For a fossil fuel-fired steam generator that burns only gaseous fossil fuel, continuous monitoring systems for measuring the opacity of emissions and sulfur dioxide emissions are not required.[57]

(2) For a fossil fuel-fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis under paragraph (d) of this section.[57]

(3) Notwithstanding § 60.13(b), installation of a continuous monitoring system for nitrogen oxides may be delayed until after the initial performance tests under § 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less than 70 percent of the applicable standards in § 60.44, a continuous monitoring system for measuring nitrogen oxides emissions is not required. If the initial performance test results show that nitrogen oxide emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a continuous monitoring system for nitrogen oxides within one year after the date of the initial performance tests under § 60.8 and comply with all other applicable monitoring requirements under this part.[57]

(4) If an owner or operator does not install any continuous monitoring systems for sulfur oxides and nitrogen oxides, as provided under paragraphs (b)(1) and (b)(3) or paragraphs (b)(2) and (b)(3) of this section a continuous monitoring system for measuring either oxygen or carbon dioxide is not required.[57]

(c) For performance evaluations under § 60.13(c) and calibration checks under § 60.13(d), the following procedures shall be used:[57]

(1) Reference Methods 6 or 7, as applicable, shall be used for conducting performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems.[57]

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B to this part.[57]

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide	Span value for nitrogen oxides
Gas	(1)	500
Liquid	1,000	500
Solid	1,500	500
Combinations	$1{,}000y + 1{,}500z$	$500(x + y) + 1{,}000z$

[1]Not applicable.

where:

x=the fraction of total heat input derived from gaseous fossil fuel, and

y=the fraction of total heat input derived from liquid fossil fuel, and

z=the fraction of total heat input derived from solid fossil fuel. [57]

(4) All span values computed under paragraph (c)(3) of this section for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm.[57]

(5) For a fossil fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all continuous monitoring systems shall be subject to the Administrator's approval.[57]

(d) [Reserved][57]

(e) For any continuous monitoring system installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):[49,57]

(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left[\frac{20.9}{20.9 - \text{percent } O_2}\right]$$

where:

E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.[57]

(2) When a continuous monitoring system for measuring carbon dioxide is selected, the measurement of the pollutant concentration and carbon dioxide concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left[\frac{100}{\text{percent } CO_2}\right]$$

where:

E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.[57]

(f) The values used in the equations under paragraphs (e) (1) and (2) of this section are derived as follows:

(1) E=pollutant emissions, ng/J (lb/million Btu).

(2) C=pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{-4} M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where M=pollutant molecular weight, g/g-mole (lb/lb-mole). M=64.07 for sulfur dioxide and 46.01 for nitrogen oxides.[49]

(3) $\%O_2$, $\%CO_2$=oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under paragraph (d) of this section.

(4) F, F_c=a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to A.S.T.M. D 388-66, $F=2.723\times10^{-7}$ dscm/J (10,140 dscf/million Btu) and $F_c=0.532\times10^{-7}$ scm CO_2/J (1,980 scf CO_2/million Btu).[49]

(ii) For subbituminous and bituminous coal as classified according to A.S.T.M. D 388-66, $F=2.637\times10^{-7}$ dscm/J (9,820 dscf/million Btu) and $F_c=0.486\times10^{-7}$ scm CO_2/J (1,810 scf CO_2/million Btu).[49]

(iii) For liquid fossil fuels including crude, residual, and distillate oils, $F=2.476\times10^{-7}$ dscm/J (9,220 dscf/million Btu) and $F_c=0.384\times10^{-7}$ scm CO_2/J (1,430 scf CO_2/million Btu).[49,67]

(iv) For gaseous fossil fuels, $F=2.347\times10^{-7}$ dscm/J (8,740 dscf/million Btu). For natural gas, propane, and butane

fuels, $F_c = 0.279 \times 10^{-7}$ scm CO_2/J (1,040 scf CO_2/million Btu) for natural gas, 0.322×10^{-7} scm CO_2/J (1,200 scf CO_2/million Btu) for propane, and 0.338×10^{-7} scm CO_2/J (1,260 scf CO_2/million Btu) for butane.[49,67]

(v) For bark $F = 2.589 \times 10^{-7}$ dscm/J (9,640 dscf/million Btu) and $F_c = 0.500 \times 10^{-7}$ scm CO_2/J (1,860 scf CO_2/ million Btu). For wood residue other than bark $F = 2.492 \times 10^{-7}$ dscm/J (9,280 dscf/million Btu) and $F_c = 0.494 \times 10^{-7}$ scm CO_2/J (1,840 scf CO_2/ million Btu).[49,67]

(vi) For lignite coal as classified according to A.S.T.M. D 388-66, $F = 2.659 \times 10^{-7}$ dscm/J (9900 dscf/million Btu) and $F_c = 0.516 \times 10^{-7}$ scm CO_2/J (1920 scf CO_2/million Btu).[84]

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/million Btu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or F_c factor (scm CO_2/J, or scf CO_2/million Btu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:[49]

$$F = 10^{-6} \frac{[227.2\ (\text{pct. H}) + 95.5\ (\text{pct. C}) + 35.6\ (\text{pct. S}) + 8.7\ (\text{pct. N}) - 28.7\ (\text{pct. O})]}{\text{GCV}}$$

(SI units)

$$F = \frac{10^6[3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)]}{GCV}$$

(English units)

$$F_c = \frac{2.0 \times 10^{-6}\ (\text{pct. C})}{\text{GCV}}.$$

(SI units)

$$F_c = \frac{321 \times 10^3(\%C)}{GCV}$$

(English units) [23,49,67]

(i) H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using A.S.T.M. method D3178-74 or D3176 (solid fuels), or computed from results using A.S.T.M. methods D1137-53(70), D1945-64(73), or D1946-67(72) (gaseous fuels) as applicable.

(ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted, determined by the A.S.T.M. test methods D2015-66(72) for solid fuels and D 1826-64(70) for gaseous fuels as applicable.[49]

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or F_c value shall be subject to the Administrator's approval.[49]

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or F_c factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \text{ or } F_c = \sum_{i=1}^{n} X_i (F_c)_i,$$

where:

X_i = the fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.)

F_i or $(F_c)_i$ = the applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section.

n = the number of fuels being burned in combination.[49]

(g) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Opacity.* Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.[76]

(i) For sources subject to the opacity standard of § 60.42(b)(1), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.[107]

(ii) For sources subject to the opacity standard of § 60.42(b)(2), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 32 percent opacity, except that one six-minute average per hour of up to 39 percent opacity need not be reported.[112]

(2) Sulfur dioxide. Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under § 60.43.

(3) Nitrogen oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under § 60.44.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68,83]

§ 60.46 Test methods and procedures.[8,18]

(a) The reference methods in Appendix A of this part, except as provided in § 60.8(b), shall be used to determine compliance with the standards as prescribed in §§ 60.42, 60.43, and 60.44 as follows:

(1) Method 1 for selection of sampling site and sample traverses.

(2) Method 3 for gas analysis to be used when applying Reference Methods 5, 6 and 7.

(3) Method 5 for concentration of particulate matter and the associated moisture content.

(4) Method 6 for concentration of SO_2, and

(5) Method 7 for concentration of NO_x.

(b) For Method 5, Method 1 shall be used to select the sampling site and the number of traverse sampling points. The sampling time for each run shall be at least 60 minutes and the minimum sampling volume shall be 0.85 dscm (30 dscf) except that smaller sampling times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator. The probe and filter holder heating systems in the sampling train shall be set to provide a gas temperature no greater than 433 K (320°F).[49]

(c) For Methods 6 and 7, the sampling site shall be the same as that selected for Method 5. The sampling point in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). For Method 6, the sample shall be extracted at a rate proportional to the gas velocity at the sampling point.

(d) For Method 6, the minimum sampling time shall be 20 minutes and the minimum sampling volume 0.02 dscm (0.71 dscf) for each sample. The arithmetic mean of two samples shall constitute one run. Samples shall be taken at approximately 30-minute intervals.

(e) For Method 7, each run shall consist of at least four grab samples taken at approximately 15-minute intervals. The arithmetic mean of the samples shall constitute the run value.

(f) For each run using the methods specified by paragraphs (a)(3), (a)(4), and (a)(5) of this section, the emissions expressed in ng/J (lb/million

Btu) shall be determined by the following procedure:

$$E = CF(20.9/20.9 - \text{percent } O_2)$$

where:

(1) E=pollutant emission ng/J (lb/million Btu).

(2) C=pollutant concentration, ng/dscm (lb/dscf), determined by method 5, 6, or 7.

(3) Percent O_2=oxygen content by volume (expressed as percent), dry basis. Percent oxygen shall be determined by using the integrated or grab sampling and analysis procedures of Method 3 as applicable.

The sample shall be obtained as follows:

(i) For determination of sulfur dioxide and nitrogen oxides emissions, the oxygen sample shall be obtained simultaneously at the same point in the duct as used to obtain the samples for Methods 6 and 7 determinations, respectively [§ 60.46(c)]. For Method 7, the oxygen sample shall be obtained using the grab sampling and analysis procedures of Method 3.

(ii) For determination of particulate emissions, the oxygen sample shall be obtained simultaneously by traversing the duct at the same sampling location used for each run of Method 5 under paragraph (b) of this section. Method 1 shall be used for selection of the number of traverse points except that no more than 12 sample points are required.

(4) F=a factor as determined in paragraphs (f) (4), (5) or (6) of § 60.45.

(g) When combinations of fossil fuels or fossil fuel and wood residue are fired, the heat input, expressed in watts (Btu/hr), is determined during each testing period by multiplying the gross calorific value of each fuel fired (in J/kg or Btu/lb) by the rate of each fuel burned (in kg/sec or lb/hr). Gross calorific values are determined in accordance with A.S.T.M. methods D 2015-66(72) (solid fuels), D 240-64(73) (liquid fuels), or D 1826-64(7) (gaseous fuels) as applicable. The method used to determine calorific value of wood residue must be approved by the Administrator. The owner or operator shall determine the rate of fuels burned during each testing period by suitable methods and shall confirm the rate by a material balance over the steam generation system.[49]

Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68,83]

Proposed/effective
36 FR 15704, 8/17/71

Promulgated
36 FR 24876, 12/23/71 (1)

Revised
37 FR 14877, 7/26/72 (2)
38 FR 28564, 10/15/73 (4)
39 FR 20790, 6/14/74 (8)
40 FR 2803, 1/16/75 (11)
40 FR 46250, 10/6/75 (18)
40 FR 59204, 12/22/75 (23)
41 FR 51397, 11/22/76 (49)
42 FR 5936, 1/31/77 (57)
42 FR 37936, 7/25/77 (64)
42 FR 41122, 8/15/77 (67)
42 FR 41424, 8/17/77 (68)
42 FR 61537, 12/5/77 (76)
43 FR 8800, 3/3/78 (83)
43 FR 9276, 3/7/78 (84)
44 FR 3491, 1/17/79 (94)
44 FR 33580, 6/11/79 (98)
44 FR 76786, 12/28/79 (107)
45 FR 8211, 2/6/80 (110)
45 FR 36077, 5/29/80 (112)

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 [98, 110]

§ 60.40a Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction or modification is commenced after September 18, 1978.

(b) This subpart applies to electric utility combined cycle gas turbines that are capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to Subpart GG.)

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

§ 60.41a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

"Steam generating unit" means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

"Electric utility steam generating unit" means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

"Subbituminous coal" means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388–66.

"Lignite" means coal that is classified as lignite A or B according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388–66.

"Coal refuse" means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

"Potential combustion concentration" means the theoretical emissions (ng/J, lb/million Btu heat input) that would result from combustion of a fuel in an uncleaned state 9without emission control systems) and:

(a) For particulate matter is:

(1) 3,000 ng/J (7.0 lb/million Btu) heat input for solid fuel; and

(2) 75 ng/J (0.17 lb/million Btu) heat input for liquid fuels.

(b) For sulfur dioxide is determined under § 60.48a(b).

(c) For nitrogen oxides is:

(1) 290 ng/J (0.67 lb/million Btu) heat input for gaseous fuels;

(2) 310 ng/J (0.72 lb/million Btu) heat input for liquid fuels; and

(3) 990 ng/J (2.30 lb/million Btu) heat input for solid fuels.

"Combined cycle gas turbine" means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

"Interconnected" means that two or more electric generating units are electrically tied together by a network of power transmission lines, and other power transmission equipment.

"Electric utility company" means the largest interconnected organization, business, or governmental entity that generates electric power for sale (e.g., a holding company with operating subsidiary companies).

"Principal company" means the electric utility company or companies which own the affected facility.

"Neighboring company" means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

"Net system capacity" means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

"System load" means the entire electric demand of an electric utility company's service area interconnected with the affected facility that has the malfunctioning flue gas desulfurization system plus firm contractual sales to other electric utility companies. Sales to other electric utility companies (e.g., emergency power) not on a firm contractual basis may also be included in the system load when no available system capacity exists in the electric utility company to which the power is supplied for sale.

"System emergency reserves" means an amount of electric generating capacity equivalent to the rated capacity of the single largest electric generating unit in the electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) which is interconnected with the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

"Available system capacity" means the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity.

"Spinning reserve" means the sum of the unutilized net generating capability of all units of the electric utility company that are synchronized to the power distribution system and that are capable of immediately accepting

additional load. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

"Available purchase power" means the lesser of the following:

(a) The sum of available system capacity in all neighboring companies.

(b) The sum of the rated capacities of the power interconnection devices between the principal company and all neighboring companies, minus the sum of the electric power load on these interconnections.

(c) The rated capacity of the power transmission lines between the power interconnection devices and the electric generating units (the unit in the principal company that has the malfunctioning flue gas desulfurization system and the unit(s) in the neighboring company supplying replacement electrical power) less the electric power load on these transmission lines.

"Spare flue gas desulfurization system module" means a separate system of sulfur dioxide emission control equipment capable of treating an amount of flue gas equal to the total amount of flue gas generated by an affected facility when operated at maximum capacity divided by the total number of nonspare flue gas desulfurization modules in the system.

"Emergency condition" means that period of time when:

(a) The electric generation output of an affected facility with a malfunctioning flue gas desulfurization system cannot be reduced or electrical output must be increased because:

(1) All available system capacity in the principal company interconnected with the affected facility is being operated, and

(2) All available purchase power interconnected with the affected facility is being obtained, or

(b) The electric generation demand is being shifted as quickly as possible from an affected facility with a malfunctioning flue gas desulfurization system to one or more electrical generating units held in reserve by the principal company or by a neighboring company, or

(c) An affected facility with a malfunctioning flue gas desulfurization system becomes the only available unit to maintain a part or all of the principal company's system emergency reserves and the unit is operated in spinning reserve at the lowest practical electric generation load consistent with not causing significant physical damage to the unit. If the unit is operated at a higher load to meet load demand, an emergency condition would not exist unless the conditions under (a) of this definition apply.

"Electric utility combined cycle gas turbine" means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Potential electrical output capacity" is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100–MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33–MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

"Anthracite" means coal that is classified as anthracite according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388–66.

"Solid-derived fuel" means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, and gasified coal.

"24-hour period" means the period of time between 12:01 a.m. and 12:00 midnight.

"Resource recovery unit" means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

"Noncontinental area" means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

"Boiler operating day" means a 24-hour period during which fossil fuel is combusted in a steam generating unit for the entire 24 hours.

§ 60.42a Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the particulate matter performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

§ 60.43a Standard for sulfur dioxide.

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases which contain sulfur dioxide in excess of:

(1) 520 ng/J (1.20 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/million Btu) heat input.

(b) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section), any gases which contain sulfur dioxide in excess of:

(1) 340 ng/J (0.80 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.

(c) On and after the date on which the initial performance test required to be

conducted under § 60.8 is complete, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC–I) any gases which contain sulfur dioxide in excess of 520 ng/J (1.20 lb/million Btu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/million Btu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite,

(2) Is classified as a resource recovery facility, or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dixoide emissions are limited to 340 ng/J (0.80 lb/million Btu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an SO_2 commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.45a.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

(1) If emissions of sulfur dioxide to the atmosphere are greater than 260 ng/J (0.60 lb/million Btu) heat input

$E_{SO_2} = [340\,x + 520\,y]/100$ and
$P_{SO_2} = 10$ percent

(2) If emissions of sulfur dioxide to the atmosphere are equal to or less than 260 ng/J (0.60 lb/million Btu) heat input:

$E_{SO_2} = [340\,x + 520\,y]/100$ and
$P_{SO_2} = [90\,x + 70\,y]/100$

where:

E_{SO_2} is the prorated sulfur dioxide emission limit (ng/J heat input),

P_{SO_2} is the percentage of potential sulfur dioxide emission allowed (percent reduction required = $100 - P_{SO_2}$),

x is the percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels)

y is the percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels)

§ 60.44a Standard for nitrogen oxides.

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraph (b) of this section, any gases which contain nitrogen oxides in excess of the following emission limits, based on a 30-day rolling average.

(1) NO_x Emission Limits—

Fuel type	Emission limit ng/J (lb/million Btu) heat input	
Gaseous Fuels:		
Coal-derived fuels	210	(0.50)
All other fuels	86	(0.20)
Liquid Fuels		
Coal-derived fuels	210	(0.50)
Shale oil	210	(0.50)
All other fuels	130	(0.30)
Solid Fuels:		
Coal-derived fuels	210	(0.50)
Any fuel containing more than 25%, by weight, coal refuse	Exempt from NO_x standards and NO_x monitoring requirements	
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace	340	(0.80)
Lignite not subject to the 340 ng/J heat input emission limit	260	(0.60)
Subbituminous coal	210	(0.50)
Bituminous coal	260	(0.60)
Anthracite coal	260	(0.60)
All other fuels	260	(0.60)

(2) NO_x reduction requirements—

Fuel type	Percent reduction of potential combustion concentration
Gaseous fuels	25%
Liquid fuels	30%
Solid fuels	65%

(b) The emission limitations under paragraph (a) of this section do not apply to any affected facility which is combusting coal-derived liquid fuel and is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.45a.

(c) When two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$E_{NO_x} = [86\,w + 130\,x + 210\,y + 260\,z]/100$

where:

E_{NO_x} is the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input);

w is the percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x is the percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y is the percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard; and

z is the percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard.

§ 60.45a Commercial demonstration permit.

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC–I) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under § 60.43a(c) but must, as a minimum, reduce SO_2 emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(c) An owner or operator of a fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under § 60.43a(a) but must, as a minimum, reduce SO_2 emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable NO_x emission limitation and percent reduction under § 60.44a(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/million Btu)

heat input on a 30-day rolling average basis.

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Solid solvent refined coal (SRC I)	SO_2	6,000–10,000
Fluidized bed combustion (atmospheric)	SO_2	400–3,000
Fluidized bed combustion (pressurized)	SO_2	400–1,200
Coal liquification	NO_x	750–10,000
Total allowable for all technologies		15,000

§ 60.46a Compliance provisions.

(a) Compliance with the particulate matter emission limitation under § 60.42a(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under § 60.42a(a)(2) and (3).

(b) Compliance with the nitrogen oxides emission limitation under § 60.44a(a) constitutes compliance with the percent reduction requirements under § 60.44a(a)(2).

(c) The particulate matter emission standards under § 60.42a and the nitrogen oxides emission standards under § 60.44a apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide emission standards under § 60.43a apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the procedures under paragraph (d) of this section are implemented.

(d) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:

(1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,

(2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation, and

(3) Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 million Btu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph (a), (b), (d), (e), and (i) under § 60.43a for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,

(ii) The affected facility is operating at the maximum heat input rate,

(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(iv) The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

(e) After the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under § 60.43a and the nitrogen oxides emission limitations under § 60.44a is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

(f) For the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under § 60.43a and the nitrogen oxides emission limitation under § 60.44a is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) Compliance is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_x only), or emergency conditions (SO_2 only). Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under § 60.47a of this subpart, compliance of the affected facility with the emission requirements under §§ 60.43a and 60.44a of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in sections 6.0 and 7.0 of Reference Method 19 (Appendix A).

§ 60.47a Emission monitoring.

(a) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.

(2) For a facility which qualifies under the provisions of § 60.43a(d), sulfur dioxide emissions are only monitored as discharged to the atmosphere.

(3) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 (Appendix A) may be used to determine

potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required under paragraph (b)(1) of this section.

(c) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

(e) The continuous monitoring systems under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(f) When emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using other monitoring systems as approved by the Administrator or the reference methods as described in paragraph (h) of this section to provide emission data for a minimum of 18 hours in at least 22 out of 30 successive boiler operating days.

(g) The 1-hour averages required under paragraph § 60.13(h) are expressed in ng/J (lbs/million Btu) heat input and used to calculate the average emission rates under § 60.46a. The 1-hour averages are calculated using the data points required under § 60.13(b). At least two data points must be used to calculate the 1-hour averages.

(h) Reference methods used to supplement continuous monitoring system data to meet the minimum data requirements in paragraph § 60.47a(f) will be used as specified below or otherwise approved by the Administrator.

(1) Reference Methods 3, 6, and 7, as applicable, are used. The sampling location(s) are the same as those used for the continuous monitoring system.

(2) For Method 6, the minimum sampling time is 20 minutes and the minimum sampling volume is 0.02 dscm (0.71 dscf) for each sample. Samples are taken at approximately 60-minute intervals. Each sample represents a 1-hour average.

(3) For Method 7, samples are taken at approximately 30-minute intervals. The arithmetic average of these two consective samples represent a 1-hour average.

(4) For Method 3, the oxygen or carbon dioxide sample is to be taken for each hour when continuous SO_2 and NO_x data are taken or when Methods 6 and 7 are required. Each sample shall be taken for a minimum of 30 minutes in each hour using the integrated bag method specified in Method 3. Each sample represents a 1-hour average.

(5) For each 1-hour average, the emissions expressed in ng/J (lb/million Btu) heat input are determined and used as needed to achieve the minimum data requirements of paragraph (f) of this section.

(i) The following procedures are used to conduct monitoring system performance evaluations under § 60.13(c) and calibration checks under § 60.13(d).

(1) Reference method 6 or 7, as applicable, is used for conducting performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems.

(2) Sulfur dioxide or nitrogen oxides, as applicable, is used for preparing calibration gas mixtures under performance specification 2 of appendix B to this part.

(3) For affected facilities burning only fossil fuel, the span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows:

Fossil fuel	Span value for nitrogen oxides (ppm)
Gas	500
Liquid	500
Solid	1,000
Combination	500 (x+y)+1,000z

where:
x is the fraction of total heat input derived from gaseous fossil fuel,
y is the fraction of total heat input derived from liquid fossil fuel, and
z is the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (b)(3) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414).)

§ 60.48a Compliance determination procedures and methods.

(a) The following procedures and reference methods are used to determine compliance with the standards for particulate matter under § 60.42a.

(1) Method 3 is used for gas analysis when applying method 5 or method 17.

(2) Method 5 is used for determining particulate matter emissions and associated moisture content. Method 17 may be used for stack gas temperatures less than 160 C (320 F).

(3) For Methods 5 or 17, Method 1 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(4) For Method 5, the probe and filter holder heating system in the sampling train is set to provide a gas temperature no greater than 160°C (32°F).

(5) For determination of particulate emissions, the oxygen or carbon-dioxide sample is obtained simultaneously with each run of Methods 5 or 17 by traversing the duct at the same sampling location. Method 1 is used for selection of the number of traverse points except that no more than 12 sample points are required.

(6) For each run using Methods 5 or 17, the emission rate expressed in ng/J heat input is determined using the oxygen or carbon-dioxide measurements and particulate matter measurements obtained under this section, the dry basis F_c-factor and the dry basis emission rate calculation procedure contained in Method 19 (Appendix A).

(7) Prior to the Administrator's issuance of a particulate matter reference method that does not experience sulfuric acid mist interference problems, particulate matter emissions may be sampled prior to a wet flue gas desulfurization system.

(b) The following procedures and methods are used to determine compliance with the sulfur dioxide standards under § 60.43a.

(1) Determine the percent of potential combustion concentration (percent PCC) emitted to the atmosphere as follows:

(i) *Fuel Pretreatment (% R_f):* Determine the percent reduction achieved by any fuel pretreatment using the procedures in Method 19 (Appendix A). Calculate the average percent reduction for fuel pretreatment on a quarterly basis using fuel analysis data. The determination of percent R_f to calculate the percent of potential combustion concentration emitted to the atmosphere is optional. For purposes of determining compliance with any percent reduction requirements under § 60.43a, any reduction in potential SO_2 emissions resulting from the following processes may be credited:

(A) Fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.),

(B) Coal pulverizers, and

(C) Bottom and flyash interactions.

(ii) *Sulfur Dioxide Control System (% R_g):* Determine the percent sulfur dioxide reduction achieved by any sulfur dioxide control system using emission rates measured before and after the control system, following the procedures in Method 19 (Appendix A); or, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19 (Appendix A). When the "as fired" fuel monitor is used, the percent reduction is calculated using the average emission rate from the sulfur dioxide control device and the average SO_2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(iii) *Overall percent reduction (% R_o):* Determine the overall percent reduction using the results obtained in paragraphs (b)(1) (i) and (ii) of this section following the procedures in Method 19 (Appendix A). Results are calculated for each 30-day period using the quarterly average percent sulfur reduction determined for fuel pretreatment from the previous quarter and the sulfur dioxide reduction achieved by a sulfur dioxide control system for each 30-day period in the current quarter.

(iv) *Percent emitted (% PCC):* Calculate the percent of potential combustion concentration emitted to the atmosphere using the following equation: Percent PCC = 100 − Percent R_o

(2) Determine the sulfur dioxide emission rates following the procedures in Method 19 (Appendix A).

(c) The procedures and methods outlined in Method 19 (Appendix A) are used in conjunction with the 30-day nitrogen-oxides emission data collected under § 60.47a to determine compliance with the applicable nitrogen oxides standard under § 60.44.

(d) Electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19 (Appendix A). The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 (Appendix A) calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

§ 60.49a Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, and particulate matter emissions, the performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or dilutent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_x only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by § 60.47a is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of § 60.46a(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (E_o*) and the upper confidence limit for the mean inlet emission rate (E_i*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o*) and the allowable emission rate (E_{std}) as applicable.

(d) If any standards under § 60.43a are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under § 60.46a(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the sulfur dioxide emission standard under § 60.43a is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the

provisions of § 60.48a and Method 19 (Appendix A); and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(h) For the purposes of the reports required under § 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under § 60.42a(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(i) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414).)

Proposed/effective
43 FR 42154, 9/19/78

Promulgated
44 FR 33580, 6/11/79 (98)

Revised
45 FR 8211, 2/6/80 (110)

Subpart E—Standards of Performance for Incinerators

§ 60.50 Applicability and designation of affected facility. [8, 64]

(a) The provisions of this subpart are applicable to each incinerator of more than 45 metric tons per day charging rate (50 tons/day), which is the affected facility.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

§ 60.51 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Incinerator" means any furnace used in the process of burning solid waste for the purpose of reducing the volume of the waste by removing combustible matter.[8]

(b) "Solid waste" means refuse, more than 50 percent of which is municipal type waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustibles, and noncombustible materials such as glass and rock.

(c) "Day" means 24 hours. [8]

§ 60.52 Standard for particulate matter.[8]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this part shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of 0.18 g/dscm (0.08 gr/dscf) corrected to 12 percent CO_2.

§ 60.53 Monitoring of operations.[8]

(a) The owner or operator of any incinerator subject to the provisions of this part shall record the daily charging rates and hours of operation.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

§ 60.54 Test methods and procedures.[8]

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.52 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis and calculation of excess air, using the integrated sample technique.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be 0.85 dscm (30.0 dscf) except that smaller sampling times or sample volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) If a wet scrubber is used, the gas analysis sample shall reflect flue gas conditions after the scrubber, allowing for carbon dioxide absorption by sampling the gas on the scrubber inlet and outlet sides according to either the procedure under paragraphs (c)(1) through (c)(5) of this section or the procedure under paragraphs (c)(1), (c)(2) and (c)(6) of this section as follows:

(1) The outlet sampling site shall be the same as for the particulate matter measurement. The inlet site shall be selected according to Method 1, or as specified by the Administrator.

(2) Randomly select 9 sampling points within the cross-section at both the inlet and outlet sampling sites. Use the first set of three for the first run, the second set for the second run, and the third set for the third run.

(3) Simultaneously with each particulate matter run, extract and analyze for CO_2 an integrated gas sample according to Method 3, traversing the three sample points and sampling at each point for equal increments of time. Conduct the runs at both inlet and outlet sampling sites.

(4) Measure the volumetric flow rate at the inlet during each particulate matter run according to Method 2, using the full number of traverse points. For the inlet make two full velocity traverses approximately one hour apart during each run and average the results. The outlet volumetric flow rate may be determined from the particulate matter run (Method 5).

(5) Calculate the adjusted CO_2 percentage using the following equation:

$$(\%\ CO_2)_{adj} = (\%\ CO_2)_{di}\ (Q_{di}/Q_{do})$$

where:

$(\%\ CO_2)_{adj}$ is the adjusted CO_2 percentage which removes the effect of CO_2 absorption and dilution air,

$(\%\ CO_2)_{di}$ is the percentage of CO_2 measured before the scrubber, dry basis,

Q_{di} is the volumetric flow rate before the scrubber, average of two runs, dscf/min (using Method 2), and

Q_{do} is the volumetric flow rate after the scrubber, dscf/min (using Methods 2 and 5).

(6) Alternatively, the following procedures may be substituted for the procedures under paragraphs (c) (3), (4), and (5) of this section:

(i) Simultaneously with each particulate matter run, extract and analyze for CO_2, O_2, and N_2 an integrated gas sample according to Method 3, traversing the three sample points and sampling for equal increments of time at each point. Conduct the runs at both the inlet and outlet sampling sites.

(ii) After completing the analysis of the gas sample, calculate the percentage of excess air (% EA) for both the inlet and outlet sampling sites using equation 3-1 in Appendix A to this part.

(iii) Calculate the adjusted CO_2 percentage using the following equation:

$$(\%\ CO_2)_{adj} = (\%\ CO_2)_{di}\left[\frac{100+(\%\ EA)_i}{100+(\%\ EA)_o}\right]$$

where:

$(\%\ CO_2)_{adj}$ is the adjusted outlet CO_2 percentage,

$(\%\ CO_2)_{di}$ is the percentage of CO_2 measured before the scrubber, dry basis,

$(\%\ EA)_i$ is the percentage of excess air at the inlet, and

$(\%\ EA)_o$ is the percentage of excess air at the outlet.

(d) Particulate matter emissions, expressed in g/dscm, shall be corrected to 12 percent CO_2 by using the following formula:

$$c_{12} = \frac{12c}{\%\ CO_2}$$

where:

c_{12} is the concentration of particulate matter corrected to 12 percent CO_2,

c is the concentration of particulate matter as measured by Method 5, and

$\%\ CO_2$ is the percentage of CO_2 as measured by Method 3, or when applicable, the adjusted outlet CO_2 percentage as determined by paragraph (c) of this section.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

Proposed/effective
36 FR 15704, 8/17/71

Promulgated
36 FR 24876, 12/23/71 (1)

Revised
39 FR 20790, 6/14/74 (8)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart F—Standards of Performance for Portland Cement Plants

§ 60.60 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to the following affected facilities in portland cement plants: kiln, clinker cooler, raw mill system, finish mill system, raw mill dryer, raw material storage, clinker storage, finished product storage, conveyor transfer points, bagging and bulk loading and unloading systems.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

§ 60.61 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Portland cement plant" means any facility manufacturing portland cement by either the wet or dry process.[8]

§ 60.62 Standard for particulate matter.[8]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any kiln any gases which:

(1) Contain particulate matter in excess of 0.15 kg per metric ton of feed (dry basis) to the kiln (0.30 lb per ton).

(2) Exhibit greater than 20 percent opacity.[10]

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any clinker cooler any gases which:

(1) Contain particulate matter in excess of 0.050 kg per metric ton of feed (dry basis) to the kiln (0.10 lb per ton).

(2) Exhibit 10 percent opacity, or greater.

(c) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility other than the kiln and clinker cooler any gases which exhibit 10 percent opacity, or greater.[18]

§ 60.63 Monitoring of operations.[8]

(a) The owner or operator of any portland cement plant subject to the provisions of this part shall record the daily production rates and kiln feed rates.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.64 Test methods and procedures.[8]

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.62 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis.

(b) For Method 5, the minimum sampling time and minimum sample volume for each run, except when process variables or other factors justify otherwise to the satisfaction of the Administrator, shall be as follows:

(1) 60 minutes and 0.85 dscm (30.0 dscf) for the kiln.

(2) 60 minutes and 1.15 dscm (40.6 dscf) for the clinker cooler.

(c) Total kiln feed rate (except fuels), expressed in metric tons per hour on a dry basis, shall be determined during each testing period by suitable methods; and shall be confirmed by a material balance over the production system.

(d) For each run, particulate matter emissions, expressed in g/metric ton of kiln feed, shall be determined by dividing the emission rate in g/hr by the kiln feed rate. The emission rate shall be determined by the equation, $g/hr = Q_s \times c$, where Q_s = volumetric flow rate of the total effluent in dscm/hr as determined in accordance with paragraph (a)(3) of this section, and c = particulate concentration in g/dscm as determined in accordance with paragraph (a)(1) of this section.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

Proposed/effective
36 FR 15704, 8/17/71

Promulgated
36 FR 24876, 12/23/71 (1)

Revised
39 FR 20790, 6/14/74 (8)
39 FR 39872, 11/12/74 (10)
40 FR 46250, 10/6/75 (18)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart G—Standards of Performance for Nitric Acid Plants

§ 60.70 Applicability and designation of affected facility. [64]

(a) The provisions of this subpart are applicable to each nitric acid production unit, which is the affected facility.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

§ 60.71 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Nitric acid production unit" means any facility producing weak nitric acid by either the pressure or atmospheric pressure process.

(b) "Weak nitric acid" means acid which is 30 to 70 percent in strength.

§ 60.72 Standard for nitrogen oxides. [3,8]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which:

(1) Contain nitrogen oxides, expressed as NO_2, in excess of 1.5 kg per metric ton of acid produced (3.0 lb per ton), the production being expressed as 100 percent nitric acid.

(2) Exhibit 10 percent opacity, or greater. [18]

§ 60.73 Emission monitoring. [18]

(a) A continuous monitoring system for the measurement of nitrogen oxides shall be installed, calibrated, maintained, and operated by the owner or operator. The pollutant gas used to prepare calibration gas mixtures under paragraph 2.1, Performance Specification 2 and for calibration checks under § 60.13(d) to this part, shall be nitrogen dioxide (NO_2). The span shall be set at 500 ppm of nitrogen dioxide. Reference Method 7 shall be used for conducting monitoring system performance evaluations under § 60.13(c).

(b) The owner or operator shall establish a conversion factor for the purpose of converting monitoring data into units of the applicable standard (kg/metric ton, lb/short ton). The conversion factor shall be established by measuring emissions with the continuous monitoring system concurrent with measuring emissions with the applicable reference method tests. Using only that portion of the continuous monitoring emission data that represents emission measurements concurrent with the reference method test periods, the conversion factor shall be determined by dividing the reference method test data averages by the monitoring data averages to obtain a ratio expressed in units of the applicable standard to units of the monitoring data, i.e., kg/metric ton per ppm (lb/short ton per ppm). The conversion factor shall be reestablished during any performance test under § 60.8 or any continuous monitoring system performance evaluation under § 60.13(c).

(c) The owner or operator shall record the daily production rate and hours of operation.

(d) [Reserved] [8]

(e) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as any three-hour period during which the average nitrogen oxides emissions (arithmetic average of three contiguous one-hour periods) as measured by a continuous monitoring system exceed the standard under § 60.72(a). [4,18]

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

§ 60.74 Test methods and procedures. [8]

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.72 as follows:

(1) Method 7 for the concentration of NO_x;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis.

(b) For Method 7, the sample site shall be selected according to Method 1 and the sampling point shall be the centroid of the stack or duct or at a point no closer to the walls than 1 m (3.28 ft). Each run shall consist of at least four grab samples taken at approximately 15-minutes intervals. The arithmetic mean of the samples shall constitute the run value. A velocity traverse shall be performed once per run.

(c) Acid production rate, expressed in metric tons per hour of 100 percent nitric acid, shall be determined during each testing period by suitable methods and shall be confirmed by a material balance over the production system.

(d) For each run, nitrogen oxides, expressed in g/metric ton of 100 percent nitric acid, shall be determined by dividing the emission rate in g/hr by the acid production rate. The emission rate shall be determined by the equation,

$$g/hr = Q_s \times c$$

where Q_s = volumetric flow rate of the effluent in dscm/hr, as determined in accordance with paragraph (a)(3) of this section, and $c = NO_x$ concentration in g/dscm, as determined in accordance with paragraph (a)(1) of this section.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

Proposed/effective
36 FR 15704, 8/17/71

Promulgated
36 FR 24876, 12/23/71 (1)

Revised
38 FR 13562, 5/23/73 (3)
38 FR 28564, 10/15/73 (4)
39 FR 20790, 6/14/74 (8)
40 FR 46250, 10/6/75 (18)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78, (83)

Subpart H—Standards of Performance for Sulfuric Acid Plants

§ 60.80 Applicability and designation of affected facility. [64]

(a) The provisions of this subpart are applicable to each sulfuric acid production unit, which is the affected facility.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

§ 60.81 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Sulfuric acid production unit" means any facility producing sulfuric acid by the contact process by burning elemental sulfur, alkylation acid, hydrogen sulfide, organic sulfides and mercaptans, or acid sludge, but does not include facilities where conversion to sulfuric acid is utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfur compounds.

(b) "Acid mist" means sulfuric acid mist, as measured by Method 8 of Appendix A to this part or an equivalent or alternative method. [8]

§ 60.82 Standard for sulfur dioxide. [8]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of 2 kg per metric ton of acid produced (4 lb per ton), the production being expressed as 100 percent H_2SO_4.

§ 60.83 Standard for acid mist. [3, 8]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which:

(1) Contain acid mist, expressed as H_2SO_4, in excess of 0.075 kg per metric ton of acid produced (0.15 lb per ton), the production being expressed as 100 percent H_2SO_4.

(2) Exhibit 10 percent opacity, or greater. [18]

§ 60.84 Emission monitoring. [18]

(a) A continuous monitoring system for the measurement of sulfur dioxide shall be installed, calibrated, maintained, and operated by the owner or operator. The pollutant gas used to prepare calibration gas mixtures under paragraph 2.1, Performance Specification 2 and for calibration checks under § 60.13(d) to this part, shall be sulfur dioxide (SO_2). Reference Method 8 shall be used for conducting monitoring system performance evaluations under § 60.13(c) except that only the sulfur dioxide portion of the Method 8 results shall be used. The span shall be set at 1000 ppm of sulfur dioxide.

(b) The owner or operator shall establish a conversion factor for the purpose of converting monitoring data into units of the applicable standard (kg/metric ton, lb/short ton). The conversion factor shall be determined, as a minimum, three times daily by measuring the concentration of sulfur dioxide entering the converter using suitable methods (e.g., the Reich test, National Air Pollution Control Administration Publication No. 999-AP-13 and calculating the appropriate conversion factor for each eight-hour period as follows:

$$CF = k\left[\frac{1.000 - 0.015r}{r - s}\right]$$

where:

CF = conversion factor (kg/metric ton per ppm, lb/short ton per ppm).

k = constant derived from material balance. For determining CF in metric units, k = 0.0653. For determining CF in English units, k = 0.1306.

r = percentage of sulfur dioxide by volume entering the gas converter. Appropriate corrections must be made for air injection plants subject to the Administrator's approval.

s = percentage of sulfur dioxide by volume in the emissions to the atmosphere determined by the continuous monitoring system required under paragraph (a) of this section.

(c) The owner or operator shall record all conversion factors and values under paragraph (b) of this section from which they were computed (i.e., CF, r, and s).

(d) [Reserved] [8]

(e) For the purpose of reports under § 60.7(c), periods of excess emissions shall be all three-hour periods (or the arithmetic average of three consecutive one-hour periods) during which the integrated average sulfur dioxide emissions exceed the applicable standards under § 60.82. [4, 18]

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

§ 60.85 Test methods and procedures. [8]

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in §§ 60.82 and 60.83 as follows:

(1) Method 8 for the concentrations of SO_2 and acid mist;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis.

(b) The moisture content can be considered to be zero. For Method 8 the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be 1.15 dscm (40.6 dscf) except that smaller sampling times or sample volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) Acid production rate, expressed in metric tons per hour of 100 percent H_2SO_4, shall be determined during each testing period by suitable methods and shall be confirmed by a material balance over the production system.

(d) Acid mist and sulfur dioxide emissions, expressed in g/metric ton of 100 percent H_2SO_4, shall be determined by dividing the emission rate in g/hr by the acid production rate. The emission rate shall be determined by the equation, $g/hr = Q_s \times c$, where Q_s = volumetric flow rate of the effluent in dscm/hr as determined in accordance with paragraph (a)(3) of this section, and c = acid mist and SO_2 concentrations in g/dscm as determined in accordance with paragraph (a)(1) of this section.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

Proposed/effective
36 FR 15704, 8/17/71

Promulgated
36 FR 24876, 12/23/71 (1)

Revised
38 FR 13562, 5/23/73 (3)
38 FR 28564, 10/15/73 (4)
39 FR 20790, 6/14/74 (8)
40 FR 46250, 10/6/75 (18)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart I—Standards of Performance for Asphalt Concrete Plants[5,100]

§ 60.90 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is each asphalt concrete plant. For the purpose of this subpart, an asphalt concrete plant is comprised only of any combination of the following: Dryers; systems for screening, handling, storing, and weighing hot aggregate; systems for loading, transferring, and storing mineral filler; systems for mixing asphalt concrete; and the loading, transfer, and storage systems associated with emission control systems.

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

§ 60.91 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Asphalt concrete plant" means any facility, as described in § 60.90, used to manufacture asphalt concrete by heating and drying aggregate and mixing with asphalt cements.

§ 60.92 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any affected facility any gases which:

(1) Contain particulate matter in excess of 90 mg/dscm (0.04 gr/dscf).

(2) Exhibit 20 percent opacity, or greater.[18]

§ 60.93 Test methods and procedures.

(a) The reference methods appended to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.92 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.9 dscm/hr (0.53 dscf/min) except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))[68,83]

Proposed/effective
38 FR 15406, 6/11/73

Promulgated
39 FR 9308, 3/8/74 (5)

Revised
40 FR 46250, 10/6/75 (18)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)
44 FR 51225, 8/31/79 (100)

Subpart J—Standards of Performance for Petroleum Refineries[5]

§ 60.100 Applicability and designation of affected facility.[64,86]

(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants of 20 long tons per day (LTD) or less. The Claus sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.[103]

(b) Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device under paragraph (a) of this section which commences construction or modification after June 11, 1973, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction or modification after October 4, 1976, is subject to the requirements of this part.

§ 60.101 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A.

(a) "Petroleum refinery" means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives.

(b) "Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(c) "Process gas" means any gas generated by a petroleum refinery process unit, except fuel gas and process upset gas as defined in this section.

(d) "Fuel gas" means natural gas or any gas generated by a petroleum refinery process unit which is combusted separately or in any combination. Fuel does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking unit coke burners.[96]

(e) "Process upset gas" means any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

(f) "Refinery process unit" means any segment of the petroleum refinery in which a specific processing operation is conducted.

(g) "Fuel gas combustion device" means any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid.[96]

(h) "Coke burn-off" means the coke removed from the surface of the fluid catalytic cracking unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in § 60.106.

(i) "Claus sulfur recovery plant" means a process unit which recovers sulfur from hydrogen sulfide by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.[86]

(j) "Oxidation control system" means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide.[86]

(k) "Reduction control system" means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to hydrogen sulfide.[86]

(l) "Reduced sulfur compounds" means hydrogen sulfide (H_2S), carbonyl sulfide (COS) and carbon disulfide (CS_2).[86]

(m) [Reserved][103]

§ 60.102 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator:[86]

(1) Particulate matter in excess of 1.0 kg/1000 kg (1.0 lb/1000 lb) of coke burn-off in the catalyst regenerator.

(2) Gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one hour period.[18,61,66]

(b) Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator or waste heat boiler in which auxiliary or supplemental liquid or solid fossil fuel is burned, particulate matter in excess of that permitted by paragraph (a)(1) of this section may be emitted to the atmosphere, except that the incremental rate of particulate matter emissions shall not exceed 43.0 g/MJ (0.10 lb/million Btu) of heat input attributable to such liquid or solid fossil fuel.[86]

§ 60.103 Standard for carbon monoxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from the fluid catalytic cracking unit catalyst regenerator any gases which contain carbon monoxide in excess of 0.050 percent by volume.

§ 60.104 Standard for sulfur dioxide.[86]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall:

(1) Burn in any fuel gas combustion device any fuel gas which contains hydrogen sulfide in excess of 230 mg/dscm (0.10 gr/dscf), except that the gases resulting from the combustion of fuel gas may be treated to control sulfur dioxide emissions provided the owner or operator demonstrates to the satisfaction of the Administrator that this is as effective in preventing sulfur dioxide emissions to the atmosphere as restricting the H_2 concentration in the fuel gas to 230 mg/dscm or less. The combustion in a flare of process upset gas, or fuel gas which is released to the flare as a result of relief valve leakage, is exempt from this paragraph.

(2) Discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of:

(i) 0.025 percent by volume of sulfur dioxide at zero percent oxygen on a dry basis if emissions are controlled by an oxidation control system, or a reduction control system followed by incineration, or

(ii) 0.030 percent by volume of reduced sulfur compounds and 0.0010 percent by volume of hydrogen sulfide calculated as sulfur dioxide at zero percent oxygen on a dry basis if emissions are controlled by a reduction control system not followed by incineration.

(b) [Reserved]

§ 60.105 Emission monitoring.[18]

(a) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator as follows:

(1) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the fluid catalytic cracking unit catalyst regenerator. The continuous monitoring system shall be spanned at 60, 70, or 80 percent opacity.

(2) An instrument for continuously monitoring and recording the concentration of carbon monoxide in gases discharged into the atmosphere from fluid catalytic cracking unit catalyst regenerators. The span of this continuous monitoring system shall be 1,000 ppm.[86]

(3) A continuous monitoring system for the measurement of sulfur dioxide in the gases discharged into the atmosphere from the combustion of fuel gases (except where a continuous monitoring system for the measurement of hydrogen sulfide is installed under paragraph (a)(4) of this section). The pollutant gas used to prepare calibration gas mixtures under paragraph 2.1,

Performance Specification 2 and for calibration checks under § 60.13(d), shall be sulfur dioxide (SO_2). The span shall be set at 100 ppm. For conducting monitoring system performance evaluations under § 60.13(c), Reference Method 6 shall be used.

(4) An instrument for continuously monitoring and recording concentrations of hydrogen sulfide in fuel gases burned in any fuel gas combustion device, if compliance with § 60.104(a)(1) is achieved by removing H_2S from the fuel gas before it is burned; fuel gas combustion devices having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas burned. The span of this continuous monitoring system shall be 300 ppm.[86]

(5) An instrument for continuously monitoring and recording concentrations of SO_2 in the gases discharged into the atmosphere from any Claus sulfur recovery plant if compliance with § 60.104(a)(2) is achieved through the use of an oxidation control system or a reduction control system followed by incineration. The span of this continuous monitoring system shall be sent at 500 ppm.[86]

(6) An instrument(s) for continuously monitoring and recording the concentration of H_2S and reduced sulfur compounds in the gases discharged into the atmosphere from any Claus sulfur recovery plant if compliance with § 60.104(a)(2) is achieved through the use of a reduction control system not followed by incineration. The span(s) of this continuous monotoring system(s) shall be set at 20 ppm for monitoring and recording the concentration of H_2S and 600 ppm for monitoring and recording the concentration of reduced sulfur compounds.[86]

(b) [Reserved]

(c) The average coke burn-off rate (thousands of kilogram/hr) and hours of operation for any fluid catalytic cracking unit catalyst regenerator subject to § 60.102 or § 60.103 shall be recorded daily.

(d) For any fluid catalytic cracking unit catalyst regenerator which is subject to § 60.102 and which utilizes an incinerator-waste heat boiler to combust the exhaust gases from the catalyst regenerator, the owner or operator shall record daily the rate of combustion of liquid or solid fossil fuels (liters/hr or kilograms/hr) and the hours of operation during which liquid or solid fossil fuels are combusted in the incinerator-waste heat boiler.

(e) For the purpose of reports under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Opacity. All one-hour periods which contain two or more six-minute periods during which the average opacity as measured by the continuous monitoring system exceeds 30 percent.[6,66]

(2) Carbon monoxide. All hourly periods during which the average carbon monoxide concentration in the gases discharged into the atmosphere from any fluid catalytic cracking unit catalyst regenerator subject to § 60.103 exceeds 0.050 percent by volume.[86]

(3) Sulfur dioxide. (i) Any three-hour period during which the average concentration of H_2S in any fuel gas combusted in any fuel gas combustion device subject to § 60.104(a)(1) exceeds 230 mg/dscm (0.10 gr/dscf), if compliance is achieved by removing H_2S from the fuel gas before it is burned; or any three-hour period during which the average concentration of SO_2 in the gases discharged into the atmosphere from any fuel gas combustion device subject to § 60.104(a)(1) exceeds the level specified in § 60.104(a)(1), if compliance is achieved by removing SO_2 from the combusted fuel gases.[86]

(ii) Any twelve-hour period during which the average concentration of SO_2 in the gases discharged into the atmosphere from any Claus sulfur recovery plant subject to § 60.104(a)(2) exceeds 250 ppm at zero percent oxygen on a dry basis if compliance with § 60.104(b) is achieved through the use of an oxidation control system or a reduction control system followed by incineration; or any twelve-hour period during which the average concentration of H_2S, or reduced sulfur compounds in the gases discharged into the atmosphere of any Claus sulfur plant subject to § 60.104(a)(2)(b) exceeds 10 ppm or 300 ppm, respectively, at zero percent oxygen and on a dry basis if compliance is achieved through the use of a reduction control system not followed by incineration.[86]

(4) Any six-hour period during which the average emissions (arithmetic average of six contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the standard under § 60.104.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))[68,83]

§ 60.106 Test methods and procedures.

(a) For the purpose of determining compliance with § 60.102(a)(1), the following reference methods and calculation procedures shall be used:

(1) For gases released to the atmosphere from the fluid catalytic cracking unit catalyst regenerator:

(i) Method 5 for the concentration of particulate matter and moisture content,

(ii) Method 1 for sample and velocity traverses, and

(iii) Method 2 for velocity and volumetric flow rate.

(2) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times may be approved by the Administrator when process variables or other factors preclude sampling for at least 60 minutes.

(3) For exhaust gases from the fluid catalytic cracking unit catalyst regenerator prior to the emission control system: the integrated sample techniques of Method 3 and Method 4 for gas analysis and moisture content, respectively; Method 1 for velocity traverses; and Method 2 for velocity and volumetric flow rate.

(4) Coke burn-off rate shall be determined by the following formula:

$$R_c = 0.2982\, Q_{RE}\,(\%CO_2 + \%CO) + 2.088\, Q_{RA} - 0.0994\, Q_{RE}\left(\frac{\%CO}{2} + \%CO_2 + \%O_2\right) \text{ (Metric Units)}$$

or

$$R_c = 0.0186\, Q_{RE}\,(\%CO_2 + \%CO) + 0.1303\, Q_{RA} - 0.0062\, Q_{RE}\left(\frac{\%CO}{2} + \%CO_2 + \%O_2\right) \text{ (English Units)}$$

where:

R_c = coke burn-off rate, kg/hr (English units: lb/hr).
0.2982 = metric units material balance factor divided by 100, kg-min/hr-m³.
0.0186 = English units material balance factor divided by 100, lb-min/hr-ft³.
Q_{RE} = fluid catalytic cracking unit catalyst regenerator exhaust gas flow rate before entering the emission control system, as determined by method 2, dscm/min (English units: dscf/min).
$\%CO_2$ = percent carbon dioxide by volume, dry basis, as determined by Method 3.
% CO = percent carbon monoxide by volume, dry basis, as determined by Method 3.
$\%O_2$ = percent oxygen by volume, dry basis, as determined by Method 3.
2.088 = metric units material balance factor divided by 100, kg-min/hr-m³.
0.1303 = English units material balance factor divided by 100, lb-min/hr-ft³.
Q_{RA} = air rate to fluid catalytic cracking unit catalyst regenerator, as determined from fluid catalytic cracking unit control room instrumentation, dscm/min (English units: dscf/min).
0.0994 = metric units material balance factor divided by 100, kg-min/hr-m³.
0.0062 = English units material balance factor divided by 100, lb-min/hr-ft³.

(5) Particulate emissions shall be determined by the following equation:

$$R_E = (60\times10^{-6})\,Q_{RV}\,C_s \text{ (Metric Units)}$$

or

$$R_E = (8.57\times10^{-3})\,Q_{RV}\,C_s \text{ (English Units)}$$

where:

R_E = particulate emission rate, kg/hr (English units: lb/hr).
60×10^{-6} = metric units conversion factor, min-kg/hr-mg.
8.57×10^{-3} = English units conversion factor, min-lb/hr-gr.
Q_{RV} = volumetric flow rate of gases discharged into the atmosphere from the fluid catalytic cracking unit catalyst regenerator following the emission control system, as determined by Method 2, dscm/min (English units: dscf/min).
C_s = particulate emission concentration discharged into the atmosphere, as determined by Method 5, mg/dscm (English units: gr/dscf).

(6) For each run, emissions expressed in kg/1000 kg (English units: lb/1000 lb) of coke burn-off in the catalyst regenerator shall be determined by the following equation:

$$R_s = 1000 \frac{R_E}{R_c} \text{ (Metric or English Units)}$$

where
R_s = particulate emission rate, kg/1000 kg (English units: lb/1000 lb) of coke burn-off in the fluid catalytic cracking unit catalyst regenerator.
1000 = conversion factor, kg to 1000 kg (English units: lb to 1000 lb).
R_E = particulate emission rate, kg/hr (English units: lb/hr).
R_c = coke burn-off rate, kg/hr (English units: lb/hr).

(7) In those instances in which auxiliary liquid or solid fossil fuels are burned in an incinerator-waste heat boiler, the rate of particulate matter emissions permitted under § 60.102(b) must be determined. Auxiliary fuel heat input, expressed in millions of cal/hr (English units: Millions of Btu/hr) shall be calculated for each run by fuel flow rate measurement and analysis of the liquid or solid auxiliary fossil fuels. For each run, the rate of particulate emissions permitted under § 60.102(b) shall be calculated from the following equation:

$$R_s = 1.0 + \frac{0.18\ H}{R_c} \text{ (Metric Units)}$$

or

$$R_s = 1.0 + \frac{0.10\ H}{R_c} \text{ (English Units)}$$

where
R_s = allowable particulate emission rate, kg/1000 kg (English units: lb/1000 lb) of coke burn-off in the fluid catalytic cracking unit catalyst regenerator.
1.0 = emission standard, 1.0 kg/1000 kg (English units: 1.0 lb/1000 lb) of coke burn-off in the fluid catalytic cracking unit catalyst regenerator.
0.18 = metric units maximum allowable incremental rate of particulate emissions, g/million cal.
0.10 = English units maximum allowable incremental rate of particulate emissions, lb/million Btu.
H = heat input from solid or liquid fossil fuel, million cal/hr (English units: million Btu/hr).
R_c = coke burn-off rate, kg/hr (English units: lb/hr).

(b) For the purpose of determining compliance with § 60.103, the integrated sample technique of Method 10 shall be used. The sample shall be extracted at a rate proportional to the gas velocity at a sampling point near the centroid of the duct. The sampling time shall not be less than 60 minutes.

(c) For the purpose of determining compliance with § 60.104(a)(1), Method 11 shall be used to determine the concentration of H_2S and Method 6 shall be used to determine the concentration of SO_2.[86]

(1) If Method 11 is used, the gases sampled shall be introduced into the sampling train at approximately atmospheric pressure. Where refinery fuel gas lines are operating at pressures substantially above atmosphere, this may be accomplished with a flow control valve. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line. The minimum sampling time shall be 10 minutes and the minimum sampling volume 0.01 dscm (0.35 dscf) for each sample. The arithmetic average of two samples of equal sampling time shall constitute one run. Samples shall be taken at approximately 1-hour intervals. For most fuel gases, sample times exceeding 20 minutes may result in depletion of the collecting solution, although fuel gases containing low concentrations of hydrogen sulfide may necessitate sampling for longer periods of time.[86]

(2) If Method 6 is used, Method 1 shall be used for velocity traverses and Method 2 for determining velocity and volumetric flow rate. The sampling site for determining SO_2 concentration by Method 6 shall be the same as for determining volumetric flow rate by Method 2. The sampling point in the duct for determining SO_2 concentration by Method 6 shall be at the centroid of the cross section if the cross sectional area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 inches) if the cross sectional area is 5 m^2 or more and the centroid is more than one meter from the wall. The sample shall be extracted at a rate proportional to the gas velocity at the sampling point. The minimum sampling time shall be 10 minutes and the minimum sampling volume 0.01 dscm (0.35 dscf) for each sample. The arithmetic average of two samples of equal sampling time shall constitute one run. Samples shall be taken at approximately 1-hour intervals.[86]

(d) For the purpose of determining compliance with § 60.104(a)(2), Method 6 shall be used to determine the concentration of SO_2 and Method 15 shall be used to determine the concentration of H_2S and reduced sulfur compounds.[86]

(1) If Method 6 is used, the procedure outlined in paragraph (c)(2) of this section shall be followed except that each run shall span a minimum of four consecutive hours of continuous sampling. A number of separate samples may be taken for each run, provided the total sampling time of these samples adds up to a minimum of four consecutive hours. Where more than one sample is used, the average SO_2 concentration for the run shall be calculated as the time weighted average of the SO_2 concentration for each sample according to the formula:

$$C_R = \sum_{i=1}^{N} C_{S_i} \frac{t_{S_i}}{T}$$

Where:
C_R = SO_2 concentration for the run.
N = Number of samples.
C_{S_i} = SO_2 concentration for sample i.
t_{S_i} = Continuous sampling time of sample i.
T = Total continuous sampling time of all N samples.[86]

(2) If Method 15 is used, each run shall consist of 16 samples taken over a minimum of three hours. The sampling point shall be at the centroid of the cross section of the duct if the cross sectional area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 inches) if the cross sectional area is 5 m^2 or more and the centroid is more than 1 meter from the wall. To insure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3 liters/minute (0.1 ft^3/min). The SO_2 equivalent for each run shall be calculated as the arithmetic average of the SO_2 equivalent of each sample during the run. Reference Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 15. The sample shall be extracted at a rate proportional to the gas velocity at the sampling point. Each run shall span a minimum of four consecutive hours of continuous sampling. A number of separate samples may be taken for each run provided the total sampling time of these samples adds up to a minimum of four consecutive hours. Where more than one sample is used, the average moisture content for the run shall be calculated as the time weighted average of the moisture content of each sample according to the formula:

$$B_{wo} = \sum_{i=1}^{N} B_{wi} \left[\frac{t_{si}}{T}\right]$$

B_{wo} = Proportion by volume of water vapor in the gas stream for the run.
N = Number of samples.
B_{wi} = Proportion by volume of water vapor in the gas stream for the sample i.
t_{si} = Continuous sampling time for sample i.
T = Total continuous sampling time of all N samples.

(Sec. 114 of the Clean Air Act, as amended [42 U.S.C. 7414]).[86]

Proposed/effective
38 FR 15406, 6/11/73
41 FR 43866, 10/4/76

Promulgated
39 FR 9308, 3/8/74 (5)

Revised
40 FR 46250, 10/6/75 (18)
42 FR 32426, 6/24/77 (61)
42 FR 37936, 7/25/77 (64)
42 FR 39389, 8/4/77 (66)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)
43 FR 10866, 3/15/78 (86)
44 FR 13480, 3/12/79 (96)
44 FR 61542, 10/25/79 (103)

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids Constructed After June 11, 1973 and Prior to May 19, 1978[111]

§ 60.110 Applicability and designation of affected facility.[64]

(a) Except as provided in § 60.110(b), the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,412 liters (40,000 gallons).

(b) This subpart does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.[8]

(c) Subject to the requirements of this subpart is any facility under paragraph (a) of this section which:

(1) Has a capacity greater than 151,416 liters (40,000 gallons), but not exceeding 246,052 liters (65,000 gallons), and commences construction or modification after March 8, 1974, and prior to May 19, 1978.[111]

(2) Has a capacity greater than 246,052 liters (65,000 gallons) and commences construction or modification after June 11, 1973, and prior to May 19, 1978.[111]

§ 60.111 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Storage vessel" means any tank, reservoir, or container used for the storage of petroleum liquids, but does not include:

(1) Pressure vessels which are designed to operate in excess of 15 pounds per square inch gauge without emissions to the atmosphere except under emergency conditions,

(2) Subsurface caverns or porous rock reservoirs, or

(3) Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.

(b) "Petroleum liquids" means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Nos. 2 through 6 fuel oils as specified in ASTM-D-396-78, gas turbine fuel oils Nos. 2-GT through 4-GT as specified in ASTM-D-2880-78, or diesel fuel oils Nos. 2-D and 4-D as specified in ASTM-D-97578.[111]

(c) "Petroleum refinery" means each facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, extracting, or reforming of unfinished petroleum derivatives.[111]

(d) "Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.[8]

(e) "Hydrocarbon" means any organic compound consisting predominantly of carbon and hydrogen.[6]

(f) "Condensate" means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature and/or pressure and remains liquid at standard conditions.

(g) "Custody transfer" means the transfer of produced petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.[8]

(h) "Drilling and production facility" means all drilling and servicing equipment, wells, flow lines, separators, equipment, gathering lines, and auxiliary non-transportation-related equipment used in the production of petroleum but does not include natural gasoline plants.[8]

(i) "True vapor pressure" means the equilibrium partial pressure exerted by a petroleum liquid as determined in accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss from Floating Roof Tanks, 1962.

(j) "Floating roof" means a storage vessel cover consisting of a double deck, pontoon single deck, internal floating cover or covered floating roof, which rests upon and is supported by the petroleum liquid being contained, and is equipped with a closure seal or seals to close the space between the roof edge and tank wall.

(k) "Vapor recovery system" means a vapor gathering system capable of collecting all hydrocarbon vapors and gases discharged from the storage vessel and a vapor disposal system capable of processing such hydrocarbon vapors and gases so as to prevent their emission to the atmosphere.

(l) "Reid vapor pressure" is the absolute vapor pressure of volatile crude oil and volatile non-viscous petroleum liquids, except liquified petroleum gases, as determined by ASTM-D-323-58 (reapproved 1968).

§ 60.112 Standard for volatile organic compounds (VOC).[111]

(a) The owner or operator of any storage vessel to which this subpart applies shall store petroleum liquids as follows:

(1) If the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a floating roof, a vapor recovery system, or their equivalents.

(2) If the true vapor pressure of the petroleum liquid as stored is greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a vapor recovery system or its equivalent.

§ 60.113 Monitoring of operations.[111]

(a) Except as provided in paragraph (d) of this section, the owner or operator subject to this subpart shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.

(b) Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(c) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).

(d) The following are exempt from the requirements of this section:

(1) Each owner or operator of each affected facility which stores petroleum liquids with a Reid vapor pressure of less than 6.9 kPa (1.0 psia) provided the maximum true vapor pressure does not exceed 6.9 kPa (1.0 psia).

(2) Each owner or operator of each affected facility equipped with a vapor recovery and return or disposal system in accordance with the requirements of § 60.112.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

Proposed/effective
38 FR 15406, 6/11/73

Promulgated
39 FR 9308, 3/8/74 (5)

Revised
39 FR 20790, 6/14/74 (8)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)
45 FR 23374, 4/4/80 (111)

Subpart Ka—Standards of Performance for Storage Vessels for Petroleum Liquids Constructed After May 18, 1978

§ 60.110a Applicability and designation of affected facility.

(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,416 liters (40,000 gallons) and for which construction is commenced after May 18, 1978.

(b) Each petroleum liquid storage vessel with a capacity of less than 1,589,873 liters (420,000 gallons) used for petroleum or condensate stored, processed, or treated prior to custody transfer is not an affected facility and, therefore, is exempt from the requirements of this subpart.

§ 60.111a Definitions.

In addition to the terms and their definitions listed in the Act and Subpart A of this part the following definitions apply in this subpart:

(a) "Storage vessel" means each tank, reservoir, or container used for the storage of petroleum liquids, but does not include:

(1) Pressure vessels which are designed to operate in excess of 204.9 kPa (15 psig) without emissions to the atmosphere except under emergency conditions.

(2) Subsurface caverns or porous rock reservoirs, or

(3) Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.

(b) "Petroleum liquids" means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Nos. 2 through 6 fuel oils as specified in ASTM-D-396-78, gas turbine fuel oils Nos. 2-GT through 4-GT as specified in ASTM-D-2880-78, or diesel fuel oils Nos. 2-D and 4-D as specified in ASTM-D-975-78.

(c) "Petroleum refinery" means each facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, extracting, or reforming of unfinished petroleum derivatives.

(d) "Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(e) "Condensate" means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

(f) "True vapor pressure" means the equilibrium partial pressure exerted by a petroleum liquid such as determined in accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss from Floating Roof Tanks, 1962.

(g) "Reid vapor pressure" is the absolute vapor pressure of volatile crude oil and volatile non-viscous petroleum liquids, except liquified petroleum gases, as determined by ASTM-D-323-58 (reapproved 1968).

(h) "Liquid-mounted seal" means a foam or liquid-filled primary seal mounted in contact with the liquid between the tank wall and the floating roof continuously around the circumference of the tank.

(i) "Metallic shoe seal" includes but is not limited to a metal sheet held vertically against the tank wall by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(j) "Vapor-mounted seal" means a foam-filled primary seal mounted continuously around the circumference of the tank so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the tank wall, the liquid surface, and the floating roof.

(k) "Custody transfer" means the transfer of produced petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.

§ 60.112a Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel to which this subpart applies which contains a petroleum liquid which, as stored, has a true vapor pressure equal to or greater than 10.3 kPa (1.5 psia) but not greater than 76.6 kPa (11.1 psia) shall equip the storage vessel with one of the following:

(1) An external floating roof, consisting of a pontoon-type or double-deck-type cover that rests on the surface of the liquid contents and is equipped with a closure device between the tank wall and the roof edge. Except as provided in paragraph (a)(1)(ii)(D) of this section, the closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal and the upper seal is referred to as the secondary seal. The roof is to be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(i) The primary seal is to be either a metallic shoe seal, a liquid-mounted seal, or a vapor-mounted seal. Each seal is to meet the following requirements:

(A) The accumulated area of gaps between the tank wall and the metallic shoe seal or the liquid-mounted seal shall not exceed 212 cm^2 per meter of tank diameter (10.0 in^2 per ft of tank diameter) and the width of any portion of any gap shall not exceed 3.81 cm (1½ in).

(B) The accumulated area of gaps between the tank wall and the vapor-mounted seal shall not exceed 21.2 cm^2 per meter of tank diameter (1.0 in^2 per ft of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (½ in).

(C) One end of the metallic shoe is to extend into the stored liquid and the other end is to extend a minimum vertical distance of 61 cm (24 in) above the stored liquid surface.

(D) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (a)(1)(ii)(B) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm^2 per meter of tank diameter (1.0 in^2 per ft of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (½ in).

(C) There are to be no holes, tears or other openings in the seal or seal fabric.

(D) The owner or operator is exempted from the requirements for secondary seals and the secondary seal gap criteria when performing gap measurements or inspections of the primary seal.

(iii) Each opening in the roof except for automatic bleeder vents and rim space vents is to provide a projection below the liquid surface. Each opening in the roof except for automatic bleeder vents, rim space vents and leg sleeves is to be equipped with a cover, seal or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use or as described in pargraph (a)(1)(iv) of this section. Automatic bleeder vents

are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting.

(iv) Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(2) A fixed roof with an internal floating type cover equipped with a continuous closure device between the tank wall and the cover edge. The cover is to be floating at all times, (i.e., off the leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the cover is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible. Each opening in the cover except for automatic bleeder vents and the rim space vents is to provide a projection below the liquid surface. Each opening in the cover except for automatic bleeder vents, rim space vents, stub drains and leg sleeves is to be equipped with a cover, seal, or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the cover is floating except when the cover is being floated off or is being landed on the leg supports. Rim vents are to be set to open only when the cover is being floated off the leg supports or at the manufacturer's recommended setting.

(3) A vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least 95 percent by weight.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in § 60.114a.

(b) The owner or operator of each storage vessel to which this subpart applies which contains a petroleum liquid which, as stored, has a true vapor pressure greater than 76.6 kPa (11.1 psia), shall equip the storage vessel with a vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least 95 percent by weight.

§ 60.113a Testing and procedures.

(a) Except as provided in § 60.8(b) compliance with the standard prescribed in § 60.112a shall be determined as follows or in accordance with an equivalent procedure as provided in § 60.114a.

(1) The owner or operator of each storage vessel to which this subpart applies which has an external floating roof shall meet the following requirements:

(i) Determine the gap areas and maximum gap widths between the primary seal and the tank wall, and the secondary seal and the tank wall according to the following frequency and furnish the Administrator with a written report of the results within 60 days of performance of gap measurements:

(A) For primary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every five years thereafter. All primary seal inspections or gap measurements which require the removal or dislodging of the secondary seal shall be accomplished as rapidly as possible and the secondary seal shall be replaced as soon as possible.

(B) For secondary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every year thereafter.

(C) If any storage vessel is out of service for a period of one year or more, subsequent refilling with petroleum liquid shall be considered initial fill for the purposes of paragraphs (a)(1)(i)(A) and (a)(1)(i)((B) of this section.

(ii) Determine gap widths in the primary and secondary seals individually by the following procedures:

(A) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(B) Measure seal gaps around the entire circumference of the tank in each place where a ⅛" diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the tank wall and measure the circumferential distance of each such location.

(C) The total surface area of each gap described in paragraph (a)(1)(ii)(B) of this section shall be determined by using probes of various widths to accurately measure the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(iii) Add the gap surface area of each gap location for the primary seal and the secondary seal individually. Divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the appropriate ratio in the standard in § 60.112a(a)(1)(i) and § 60.112a(a)(1)(ii).

(iv) Provide the Administrator 30 days prior notice of the gap measurement to afford the Administrator the opportunity to have an observer present.

(2) The owner or operator of each storage vessel to which this subpart applies which has a vapor recovery and return or disposal system shall provide the following information to the Administrator on or before the date on which construction of the storage vessel commences:

(i) Emission data, if available, for a similar vapor recovery and return or disposal system used on the same type of storage vessel, which can be used to determine the efficiency of the system. A complete description of the emission measurement method used must be included.

(ii) The manufacturer's design specifications and estimated emission reduction capability of the system.

(iii) The operation and maintenance plan for the system.

(iv) Any other information which will be useful to the Administrator in evaluating the effectiveness of the system in reducing VOC emissions.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))

§ 60.114a Equivalent equipment and procedures.

(a) Upon written application from an owner or operator and after notice and opportunity for public hearing, the Administrator may approve the use of equipment or procedures, or both, which have been demonstrated to his satisfaction to be equivalent in terms of reduced VOC emissions to the atmosphere to the degree prescribed for compliance with a specific paragraph(s) of this subpart.

(b) The owner or operator shall provide the following information in the application for determination of equivalency:

(1) Emission data, if available, which can be used to determine the effectiveness of the equipment or procedures in reducing VOC emissions from the storage vessel. A complete description of the emission measurement method used must be included.

(2) The manufacturer's design specifications and estimated emission reduction capability of the equipment.

(3) The operation and maintenance plan for the equipment.

(4) Any other information which will be useful to the Administrator in evaluating the effectiveness of the

equipment or procedures in reducing VOC emissions.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 60.115a Monitoring of operations.

(a) Except as provided in paragraph (d) of this section, the owner or operator subject to this subpart shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.

(b) Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(c) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).

(d) The following are exempt from the requirements of this section:

(1) Each owner or operator of each storage vessel storing a petroleum liquid with a Reid vapor pressure of less than 6.9 kPa (1.0 psia) provided the maximum true vapor pressure does not exceed 6.9 kPa (1.0 psia).

(2) Each owner or operator of each storage vessel equipped with a vapor recovery and return or disposal system in accordance with the requirements of §§ 60.112a(a)(3) and 60.112a(b).

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

Proposed/effective
43 FR 21616, 5/18/78

Promulgated
45 FR 23374, 4/4/80 (111)

Subpart L—Standards of Performance for Secondary Lead Smelters[5]

§ 60.120 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to the following affected facilities in secondary lead smelters. Pot furnaces of more than 250 kg (550 lb) charging capacity, blast (cupola) furnaces, and reverberatory furnaces.

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

§ 60.121 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Reverberatory furnace" includes the following types of reverberatory furnaces: stationary, rotating, rocking, and tilting.

(b) "Secondary lead smelter" means any facility producing lead from a leadbearing scrap material by smelting to the metallic form.

(c) "Lead" means elemental lead or alloys in which the predominant component is lead.[6]

§ 60.122 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from a blast (cupola) or reverberatory furnace any gases which:

(1) Contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any pot furnace any gases which exhibit 10 percent opacity or greater.[18]

§ 60.123 Test methods and procedures.

(a) The reference methods appended to this part, except as provided for in § 60.8 (b), shall be used to determine compliance with the standards prescribed in § 60.122 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.9 dscm/hr (0.53 dscf/min) except that shorter sampling times, when necesitated by process variables or other factors, may be approved by the Administrator. Particulate sampling shall be conducted during representative periods of furnace operation, including charging and tapping.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))[68,83]

Proposed/effective
38 FR 15406, 6/11/73

Promulgated
39 FR 9308, 3/8/74 (5)

Revised
39 FR 13776, 4/17/74 (6)
40 FR 46250, 10/6/75 (18)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart M—Standards of Performance for Secondary Brass and Bronze Ingot Production Plants[5]

§ 60.130 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to the following affected facilities in secondary brass or bronze ingot production plants: Reverberatory and electric furnaces of 1,000 kg (2,205 lb) or greater production capacity and blast (cupola) furnaces of 250 kg/hr (550 lb/hr) or greater production capacity.

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

§ 60.131 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Brass or bronze" means any metal alloy containing copper as its predominant constituent, and lesser amounts of zinc, tin, lead, or other metals.

(b) "Reverberatory furnace" includes the following types of reverberatory furnaces: Stationary, rotating, rocking, and tilting.

(c) "Electric furnace" means any furnace which uses electricity to produce over 50 percent of the heat required in the production of refined brass or bronze.

(d) "Blast furnace" means any furnace used to recover metal from slag

§ 60.132 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from a reverberatory furnace any gases which:

(1) Contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any blast (cupola) or electric furnace any gases which exhibit 10 percent opacity or greater.[18]

§ 60.133 Test methods and procedures.

(a) The reference methods appended to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.132 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content.

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling time for each run shall be at least 120 minutes and the sampling rate shall be at least 0.9 dscm/hr (0.53 dscf/min) except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator. Particulate matter sampling shall be conducted during representative periods of charging and refining, but not during pouring of the heat.

(Sec. 114, Clean Air Act as amended (42 U.S.C 7414))[68,83]

Proposed/effective
38 FR 15406, 6/11/73

Promulgated
39 FR 9308, 3/8/74 (5)

Revised
40 FR 46250, 10/6/75 (18)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart N—Standards of Performance for Iron and Steel Plants [5]

§ 60.140 Applicability and designation of affected facility. [64]

(a) The affected facility to which the provisions of this subpart apply is each basic oxygen process furnace.

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

§ 60.141 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Basic oxygen process furnace" (BOPF) means any furnace producing steel by charging scrap steel, hot metal, and flux materials into a vessel and introducing a high volume of an oxygen-rich gas.

(b) "Steel production cycle" means the operations required to produce each batch of steel and includes the following major functions: Scrap charging, preheating (when used), hot metal charging, primary oxygen blowing, additional oxygen blowing (when used), and tapping.

(c) "Startup means the setting into operation for the first steel production cycle of a relined BOPF or a BOPF which has been out of production for a minimum continuous time period of eight hours. [88]

§ 60.142 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any affected facility any gases which:

(1) Contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

(2) Exit from a control device and exhibit 10 percent opacity or greater, except that an opacity of greater than 10 percent but less than 20 percent may occur once per steel production cycle. [88]

§ 60.143 Monitoring of operations. [88]

(a) The owner or operator of an affected facility shall maintain a single time-measuring instrument which shall be used in recording daily the time and duration of each steel production cycle, and the time and duration of any diversion of exhaust gases from the main stack servicing the BOPF.

(b) The owner or operator of any affected facility that uses venturi scrubber emission control equipment shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(1) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±250 Pa (±1 inch water).

(2) A monitoring device for the continous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of the design water supply pressure. The monitoring device's pressure sensor or pressure tap must be located close to the water discharge point. The Administrator may be consulted for approval of alternative locations for the pressure sensor or tap.

(3) All monitoring devices shall be synchronized each day with the time-measuring instrument used under paragraph (a) of this section. The chart recorder error directly after synchronization shall not exceed 0.08 cm (1/32 inch).

(4) All monitoring devices shall use chart recorders which are operated at a minimum chart speed of 3.8 cm/hr (1.5 in/hr).

(5) All monitoring devices are to be recalibreated annually, and at other times as the Administrator may require, in accordance with the proceduces under § 60.13(b)(3).

(c) Any owner or operator subject to requirements under paragraph (b) of this section shall report for each calendar quarter all measurements over any three-hour period that average more than 10 percent below the average levels maintained during the most recent performance test conducted under § 60.8 in which the affected facility demonstrated compliance with the standard under § 60.142(a)(1). The accuracy of the respective measurements, not to exceed the values specified in paragraphs (b)(1) and (b)(2) of this section, may be taken into consideration when determining the measurement results that must be reported.

§ 60.144 Test methods and procedures.

(a) The reference methods appended to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.142 as follows:

(1) Method 5 for concentration of particulate matter and associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for volumetric flow rate, and

(4) Method 3 for gas analysis.

(5) Method 9 for visible emissions. For the purpose of this subpart, opacity observations taken at 15-second intervals immediately before and after a diversion of exhaust gases from the stack may be considered to be consecutive for the purpose of computing an average opacity for a six-minute period. Observations taken during a diversion shall not be used in determining compliance with the opacity standard. [88]

(b) For Method 5, the sampling for each run shall continue for an integral number of cycles with total duration of at least 60 minutes. The sampling rate shall be at least 0.9 dscm/hr (0.53 dscf/min) except that shorter sampling times,

(c) Sampling of flue gases during each steel production cycle shall be discontinued whenever all flue gases are diverted from the stack and shall be resumed after each diversion period. [88]

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

Proposed/effective
38 FR 15406, 6/11/73

Promulgated
39 FR 9308, 3/8/74 (5)

Revised
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)
43 FR 15600, 4/13/78 (88)

Subpart O—Standards of Performance for Sewage Treatment Plants [5]

§ 60.150 Applicability and designation of affected facility. [75]

(a) The affected facility is each incinerator that combusts wastes containing more than 10 percent sewage sludge (dry basis) produced by municipal sewage treatment plants, or each incinerator that charges more than 1000 kg (2205 lb) per day municipal sewage sludge (dry basis).

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

§ 60.151 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

§ 60.152 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator of any sewage sludge incinerator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere of:

(1) Particulate matter at a rate in excess of 0.65 g/kg dry sludge input (1.30 lb/ton dry sludge input).

(2) Any gases which exhibit 20 percent opacity or greater. [18]

§ 60.153 Monitoring of operations. [75]

(a) The owner or operator of any sludge incinerator subject to the provisions of this subpart shall:

(1) Install, calibrate, maintain, and operate a flow measuring device which can be used to determine either the mass or volume of sludge charged to the incinerator. The flow measuring device shall have an accuracy of ±5 percent over its operating range.

(2) Provide access to the sludge charged so that a well mixed representative grab sample of the sludge can be obtained.

(3) Install, calibrate, maintain, and operate a weighing device for determining the mass of any municipal solid waste charged to the incinerator when sewage sludge and municipal solid waste are incinerated together. The weighing device shall have an accuracy of ±5 percent over its operating range.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

§ 60.154 Test Methods and Procedures.

(a) The reference methods appended to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.152 as follows:

(1) Method 5 for concentration of particulate matter and associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) **Dry sludge charging rate shall be determined as follows:**

(1) Determine the mass (S_M) or volume (S_V) of sludge charged to the incinerator during each run using a flow measuring device meeting the requirements of § 60.153(a)(1). If total input during a run is measured by a flow measuring device, such readings shall be used. Otherwise, record the flow measuring device readings at 5-minute intervals during a run. Determine the quantity charged during each interval by averaging the flow rates at the beginning and end of the interval and then multiplying the average for each interval by the time for each interval. Then add the quantity for each interval to determine the total quantity charged during the entire run, (S_M) or (S_V).

(2) Collect samples of the sludge charged to the incinerator in non-porous collecting jars at the beginning of each run and at approximately 1-hour intervals thereafter until the test ends, and determine for each sample the dry sludge content (total solids residue) in accordance with "224 G. Method for Solid and Semisolid Samples," *Standard Methods for the Examination of Water and Wastewater*, Thirteenth Edition, American Public Health Association, Inc., New York, N.Y., 1971, pp. 539–41, except that:

(i) Evaporating dishes shall be ignited to at least 103°C rather than the 550°C specified in step 3(a)(1).

(ii) Determination of volatile residue, step 3(b) may be deleted.

(iii) The quantity of dry sludge per unit sludge charged shall be determined in terms of either R_{DV} (metric units: mg dry sludge/liter sludge charged or English units: lb/ft³) or R_{DM} (metric units: mg dry sludge/mg sludge charged or English units: lb/lb).

(3) Determine the quantity of dry sludge per unit sludge charged in terms of either R_{DV} or R_{DM}.

(i) If the volume of sludge charged is used:

$$S_D = (60 \times 10^{-6}) \frac{R_{DV} S_V}{T} \text{ (Metric Units)}$$

or

$$S_D = (8.021) \frac{R_{DV} S_V}{T} \text{ (English Units)}$$

where:

S_D = average dry sludge charging rate during the run, kg/hr (English units: lb/hr).
R_{DV} = average quantity of dry sludge per unit volume of sludge charged to the incinerator, mg/l (English units: lb/ft³).
S_V = sludge charged to the incinerator during the run, m³ (English units: gal).
T = duration of run, min (English units: min).
60×10^{-6} = metric units conversion factor, 1-kg-min/m³-mg-hr.
8.021 = English units conversion factor, ft³-min/gal-hr. [6]

(ii) If the mass of sludge charged is used:

$$S_D = (60) \frac{R_{DM} S_M}{T} \text{ (Metric or English Units)}$$

where:

S_D = average dry sludge charging rate during the run, kg/hr (English units: lb/hr).
R_{DM} = average ratio of quantity of dry sludge to quantity of sludge charged to the incinerator, mg/mg (English units: lb/lb).
S_M = sludge charged during the run, kg (English units: lb).
T = duration of run, min (Metric or English units). [6]
60 = conversion factor, min/hr (Metric or English units).

(d) **Particulate emission rate shall be determined by:**

$$C_{sw} = C_s Q_s \text{ (Metric or English Units)}$$

where:

C_{sw} = particulate matter mass emissions, mg/hr (English units: lb/hr). [7]
C_s = particulate matter concentration, mg/m³ (English units: lb/dscf).
Q_s = volumetric stack gas flow rate, dscm/hr (English units: dscf/hr). Q_s and C_s shall be determined using Methods 2 and 5, respectively.

(e) **Compliance with § 60.152(a) shall be determined as follows:**

$$C_{ds} = (10^{-6}) \frac{C_{sw}}{S_D} \text{ (Metric Units)}$$

or

$$C_{ds} = (2000) \frac{C_{sw}}{S_D} \text{ (English Units)}$$

where:

C_{ds} = particulate emission discharge, g/kg dry sludge (English units: lb/ton dry sludge).
10^{-6} = Metric conversion factor, g/mg.
2000 = English conversion factor, lb/ton.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

Proposed/effective
38 FR 15406, 6/11/73

Promulgated
39 FR 9308, 3/8/74 (5)

Revised
39 FR 13776, 4/17/74 (6)
39 FR 15396, 5/3/74 (7)
40 FR 46250, 10/6/75 (18)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
42 FR 58520, 11/10/77 (75)
43 FR 8800, 3/3/78 (83)

Subpart P—Standards of Performance for Primary Copper Smelters [26]

§ 60.160 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are aplicable to the following affected facilities in primary copper smelters: dryer, roaster, smelting furnace, and copper converter.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 16, 1974, is subject to the requirements of this subpart.

§ 60.161 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Primary copper smelter" means any installation or any intermediate process engaged in the production of copper from copper sulfide ore concentrates through the use of pyrometallurgical techniques.

(b) "Dryer" means any facility in which a copper sulfide ore concentrate charge is heated in the presence of air to eliminate a portion of the moisture from the charge, provided less than 5 percent of the sulfur contained in the charge is eliminated in the facility.

(c) "Roaster" means any facility in which a copper sulfide ore concentrate charge is heated in the presence of air to eliminate a significant portion (5 percent or more) of the sulfur contained in the charge.

(d) "Calcine" means the solid materials produced by a roaster.

(e) "Smelting" means processing techniques for the melting of a copper sulfide ore concentrate or calcine charge leading to the formation of separate layers of molten slag, molten copper, and/or copper matte.

(f) "Smelting furnace" means any vessel in which the smelting of copper sulfide ore concentrates or calcines is performed and in which the heat necessary for smelting is provided by an electric current, rapid oxidation of a portion of the sulfur contained in the concentrate as it passes through an oxidizing atmosphere, or the combustion of a fossil fuel.

(g) "Copper converter" means any vessel to which copper matte is charged and oxidized to copper.

(h) "Sulfuric acid plant" means any facility producing sulfuric acid by the contact process.

(i) "Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

(j) "Reverberatory smelting furnace" means any vessel in which the smelting of copper sulfide ore concentrates or calcines is performed and in which the heat necessary for smelting is provided primarily by combustion of a fossil fuel.

(k) "Total smelter charge" means the weight (dry basis) of all copper sulfides ore concentrates processed at a primary copper smelter, plus the weight of all other solid materials introduced into the roasters and smelting furnaces at a primary copper smelter, except calcine, over a one-month period.

(l) "High level of volatile impurities" means a total smelter charge containing more than 0.2 weight percent arsenic, 0.1 weight percent antimony, 4.5 weight percent lead or 5.5 weight percent zinc, on a dry basis.

§ 60.162 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any dryer any gases which contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

§ 60.163 Standard for sulfur dioxide.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any roaster, smelting furnace, or copper converter any gases which contain sulfur dioxide in excess of 0.065 percent by volume, except as provided in paragraphs (b) and (c) of this section.

(b) Reverberatory smelting furnaces shall be exempted from paragraph (a) of this section during periods when the total smelter charge at the primary copper smelter contains a high level of volatile impurities.

(c) A change in the fuel combusted in a reverberatory furnace shall not be considered a modification under this part.

§ 60.164 Standard for visible emissions.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any dryer any visible emissions which exhibit greater than 20 percent opacity.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility that uses a sulfuric acid to comply with the standard set forth in § 60.163, any visible emissions which exhibit greater than 20 percent opacity.

§ 60.165 Monitoring of operations.

(a) The owner or operator of any primary copper smelter subject to § 60.163 (b) shall keep a monthly record of the total smelter charge and the weight percent (dry basis) of arsenic, antimony, lead and zinc contained in this charge. The analytical methods and procedures employed to determine the weight of the total smelter charge and the weight percent of arsenic, antimony, lead and zinc shall be approved by the Administrator and shall be accurate to within plus or minus ten percent. [30]

(b) The owner or operator of any primary copper smelter subject to the provisions of this subpart shall install and operate:

(1) A continuous monitoring system to monitor and record the opacity of gases discharged into the atmosphere from any dryer. The span of this system shall be set at 80 to 100 percent opacity.

(2) A continuous monitoring system to monitor and record sulfur dioxide emissions discharged into the atmosphere from any roaster, smelting furnace or copper converter subject to § 60.163 (a). The span of this system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(i) The continuous monitoring system performance evaluation required under § 60.13(c) shall be completed prior to the initial performance test required under § 60.8. During the performance evaluation, the span of the continuous monitoring system may be set at a sulfur dioxide concentration of 0.15 percent by volume if necessary to maintain the system output between 20 percent and 90 percent of full scale. Upon completion of the continuous monitoring system performance evaluation, the span of the continuous monitoring system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(ii) For the purpose of the continuous monitoring system performance evaluation required under § 60.13(c) the reference method referred to under the Field Test for Accuracy (Relative) in Performance Specification 2 of Appendix B to this part shall be Reference Method 6. For the performance evaluation, each concentration measurement shall be of one hour duration. The pollutant gas used to prepare the calibration gas mixtures required under paragraph 2.1, Performance Specification 2 of Appendix B, and for calibration checks under § 60.13 (d), shall be sulfur dioxide.

(c) Six-hour average sulfur dioxide concentrations shall be calculated and recorded daily for the four consecutive 6-hour periods of each operating day. Each six-hour average shall be determined as the arithmetic mean of the appropriate six contiguous one-hour average sulfur dioxide concentrations provided by the continuous monitoring system installed under paragraph (b) of this section.

(d) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Opacity. Any six-minute period during which the average opacity, as measured by the continuous monitoring

system installed under paragraph (b) of this section, exceeds the standard under § 60.164(a).

(2) Sulfur dioxide. All six-hour periods during which the average emissions of sulfur dioxide, as measured by the continuous monitoring system installed under § 60.163, exceed the level of the standard. The Administrator will not consider emissions in excess of the level of the standard for less than or equal to 1.5 percent of the six-hour periods during the quarter as indicative of a potential violation of § 60.11(d) provided the affected facility, including air pollution control equipment, is maintained and operated in a manner consistent with good air pollution control practice for minimizing emissions during these periods. Emissions in excess of the level of the standard during periods of startup, shutdown, and malfunction are not to be included within the 1.5 percent.[74]

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.166 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in §§ 60.162, 60.163 and 60.164 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content.

(2) Sulfur dioxide concentrations shall be determined using the continuous monitoring system installed in accordance with § 60.165(b). One 6-hour average period shall constitute one run. The monitoring system drift during any run shall not exceed 2 percent of span.

(b) For Method 5, Method 1 shall be used for selecting the sampling site and the number of traverse points, Method 2 for determining velocity and volumetric flow rate and Method 3 for determining the gas analysis. The sampling time for each run shall be at least 60 minutes and the minimum sampling volume shall be 0 85 dscm (30 dscf) except that smaller times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68 83]

Proposed/effective
39 FR 37040, 10/16/74

Promulgated
41 FR 2331, 1/15/76 (26)

Revised
41 FR 8346, 2/26/76 (30)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
42 FR 57126, 11/1/77 (74)
43 FR 8800, 3/3/78 (83)

Subpart Q—Standards of Performance for Primary Zinc Smelters [26]

§ 60.170 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to the following affected facilities in primary zinc smelters: roaster and sintering machine.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 16, 1974, is subject to the requirements of this subpart.

§ 60.171 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Primary zinc smelter" means any installation engaged in the production, or any intermediate process in the production, of zinc or zinc oxide from zinc sulfide ore concentrates through the use of pyrometallurgical techniques.

(b) "Roaster" means any facility in which a zinc sulfide ore concentrate charge is heated in the presence of air to eliminate a significant portion (more than 10 percent) of the sulfur contained in the charge.

(c) "Sintering machine" means any furnace in which calcines are heated in the presence of air to agglomerate the calcines into a hard porous mass called "sinter."

(d) "Sulfuric acid plant" means any facility producing sulfuric acid by the contact process.

§ 60.172 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any sintering machine any gases which contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

§ 60.173 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any roaster any gases which contain sulfur dioxide in excess of 0.065 percent by volume.

(b) Any sintering machine which eliminates more than 10 percent of the sulfur initially contained in the zinc sulfide ore concentrates will be considered as a roaster under paragraph (a) of this section.

§ 60.174 Standard for visible emissions.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any sintering machine any visible emissions which exhibit greater than 20 percent opacity.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility that uses a sulfuric acid plant to comply with the standard set forth in § 60.173, any visible emissions which exhibit greater than 20 percent opacity.

§ 60.175 Monitoring of operations.

(a) The owner or operator of any primary zinc smelter subject to the provisions of this subpart shall install and operate:

(1) A continuous monitoring system to monitor and record the opacity of gases discharged into the atmosphere from any sintering machine. The span of this system shall be set at 80 to 100 percent opacity.

(2) A continuous monitoring system to monitor and record sulfur dioxide emissions discharged into the atmosphere from any roaster subject to § 60.173. The span of this system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(i) The continuous monitoring system performance evaluation required under § 60.13(c) shall be completed prior to the initial performance test required under § 60.8. During the performance evaluation, the span of the continuous monitoring system may be set at a sulfur dioxide concentration of 0.15 percent by volume if necessary to maintain the system output between 20 percent and 90 percent of full scale. Upon completion of the continuous monitoring system performance evaluation, the span of the continuous monitoring system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(ii) For the purpose of the continuous monitoring system performance evaluation required under § 60.13(c), the reference method referred to under the Field Test for Accuracy (Relative) in Performance Specification 2 of Appendix B to this part shall be Reference Method 6. For the performance evaluation, each concentration measurement shall be of one hour duration. The pollutant gas used to prepare the calibration gas mixtures required under paragraph 2.1, Performance Specification 2 of Appendix B, and for calibration checks under § 60.13 (d), shall be sulfur dioxide.

(b) Two-hour average sulfur dioxide concentrations shall be calculated and recorded daily for the twelve consecutive 2-hour periods of each operating day. Each two-hour average shall be determined as the arithmetic mean of the appropriate two contiguous one-hour average sulfur dioxide concentrations provided by the continuous monitoring system installed under paragraph (a) of this section.

(c) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Opacity. Any six-minute period during which the average opacity, as measured by the continuous monitoring system installed under paragraph (a) of this section, exceeds the standard under § 60.174(a).

(2) Sulfur dioxide. Any two-hour period, as described in paragraph (b) of this section, during which the average emissions of sulfur dioxide, as measured by the continuous monitoring system installed under paragraph (a) of this section, exceeds the standard under § 60.173.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.176 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in §§ 60.172, 60.173 and 60.174 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content.

(2) Sulfur dioxide concentrations shall be determined using the continuous monitoring system installed in accordance with § 60.175(a). One 2-hour average period shall constitute one run.

(b) For Method 5, Method 1 shall be used for selecting the sampling site and the number of traverse points, Method 2 for determining velocity and volumetric flow rate and Method 3 for determining the gas analysis. The sampling time for each run shall be at least 60 minutes and the minimum sampling volume shall be 0.85 dscm (30 dscf) except that smaller times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

Proposed/effective
39 FR 37040, 10/16/74

Promulgated
41 FR 2331, 1/15/76 (26)

Revised
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart R—Standards of Performance for Primary Lead Smelters [26]

§ 60.180 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to the following affected facilities in primary lead smelters: sintering machine, sintering machine discharge end, blast furnace, dross reverberatory furnace, electric smelting furnace, and converter.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 16, 1974, is subject to the requirements of this subpart.

§ 60.181 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Primary lead smelter" means any installation or any intermediate process engaged in the production of lead from lead sulfide ore concentrates through the use of pyrometallurgical techniques.

(b) "Sintering machine" means any furnace in which a lead sulfide ore concentrate charge is heated in the presence of air to eliminate sulfur contained in the charge and to agglomerate the charge into a hard porous mass called "sinter."

(c) "Sinter bed" means the lead sulfide ore concentrate charge within a sintering machine.

(d) "Sintering machine discharge end" means any apparatus which receives sinter as it is discharged from the conveying grate of a sintering machine.

(e) "Blast furnace" means any reduction furnace to which sinter is charged and which forms separate layers of molten slag and lead bullion.

(f) "Dross reverberatory furnace" means any furnace used for the removal or refining of impurities from lead bullion.

(g) "Electric smelting furnace" means any furnace in which the heat necessary for smelting of the lead sulfide ore concentrate charge is generated by passing an electric current through a portion of the molten mass in the furnace.

(h) "Converter" means any vessel to which lead concentrate or bullion is charged and refined.

(i) "Sulfuric acid plant" means any facility producing sulfuric acid by the contact process.

§ 60.182 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any blast furnace, dross reverberatory furnace, or sintering machine discharge end any gases which contain particulate matter in excess of 59 mg/dscm (0.022 gr/dscf).

§ 60.183 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any sintering machine, electric smelting furnace, or converter gases which contain sulfur dioxide in excess of 0.065 percent by volume.

§ 60.184 Standard for visible emissions.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any blast furnace, dross reverberatory furnace, or sintering machine discharge end any visible emissions which exhibit greater than 20 percent opacity.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility that uses a sulfuric acid plant to comply with the standard set forth in § 60.183, any visible emissions which exhibit greater than 20 percent opacity.

§ 60.185 Monitoring of operations.

(a) The owner or operator of any primary lead smelter subject to the provisions of this subpart shall install and operate:

(1) A continuous monitoring system to monitor and record the opacity of gases discharged into the atmosphere from any blast furnace, dross reverberatory furnace, or sintering machine discharge end. The span of this system shall be set at 80 to 100 percent opacity.

(2) A continuous monitoring system to monitor and record sulfur dioxide emissions discharged into the atmosphere from any sintering machine, electric furnace or converter subject to § 60.183. The span of this system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(i) The continuous monitoring system performance evaluation required under § 60.13(c) shall be completed prior to the initial performance test required under § 60.8. During the performance evaluation, the span of the continuous monitoring system may be set at a sulfur dioxide concentration of 0.15 percent by volume if necessary to maintain the system output between 20 percent and 90 percent of full scale. Upon completion of the continuous monitoring system performance evaluation, the span of the continuous monitoring system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(ii) For the purpose of the continuous monitoring system performance evaluation required under § 60.13(c), the reference method referred to under the Field Test for Accuracy (Relative) in Performance Specification 2 of Appendix B to this part shall be Reference Method 6. For the performance evaluation, each concentration measurement shall be of one hour duration. The pollutant gases used to prepare the calibration gas mixtures required under paragraph 2.1, Performance Specification 2 of Appendix B, and for calibration checks under § 60.13 (d), shall be sulfur dioxide.

(b) Two-hour average sulfur dioxide concentrations shall be calculated and recorded daily for the twelve consecutive two-hour periods of each operating day. Each two-hour average shall be determined as the arithmetic mean of the appropriate two contiguous one-hour average sulfur dioxide concentrations provided by the continuous monitoring system installed under paragraph (a) of this section.

(c) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Opacity. Any six-minute period during which the average opacity, as measured by the continuous monitoring system installed under paragraph (a) of this section, exceeds the standard under § 60.184(a).

(2) Sulfur dioxide. Any two-hour period, as described in paragraph (b) of this section, during which the average emissions of sulfur dioxide, as measured by the continuous monitoring system installed under paragraph (a) of this section, exceeds the standard under § 60.183.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

§ 60.186 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in §§ 60.182, 60.183 and 60.184 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content.

(2) Sulfur dioxide concentrations shall be determined using the continuous monitoring system installed in accordance with § 60.185(a). One 2-hour average period shall constitute one run.

(b) For Method 5, Method 1 shall be used for selecting the sampling site and the number of traverse points, Method 2 for determining velocity and volumetric flow rate and Method 3 for determining the gas analysis. The sampling time for each run shall be at least 60 minutes and the minimum sampling volume shall be 0.85 dscm (30 dscf) except that smaller times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

Proposed/effective	Revised
39 FR 37040, 10/16/74	42 FR 37936, 7/25/77 (64)
Promulgated	42 FR 41424, 8/17/77 (68)
41 FR 2331, 1/15/76 (26)	43 FR 8800, 3/3/78 (83)

Subpart S—Standards of Performance for Primary Aluminum Reduction Plants[27]

Authority: Sections 111 and 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

§ 60.190 Applicability and designation of affected facility.[64]

(a) The affected facilities in primary aluminum reduction plants to which this subpart applies are potroom groups and anode bake plants.[114]

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 23, 1974, is subject to the requirements of this subpart.

§ 60.191 Definitions.[114]

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

"Aluminum equivalent" means an amount of aluminum which can be produced from a Mg of anodes produced by an anode bake plant as determined by § 60.195(g).

"Anode bake plant" means a facility which produces carbon anodes for use in a primary aluminum reduction plant.

"Potroom" means a building unit which houses a group of electrolytic cells in which aluminum is produced.

"Potroom group" means an uncontrolled potroom, a potroom which is controlled individually, or a group of potrooms or potroom segments ducted to a common control system.

"Primary aluminum reduction plant" means any facility manufacturing aluminum by electrolytic reduction.

"Primary control system" means an air pollution control system designed to remove gaseous and particulate flourides from exhaust gases which are captured at the cell.

"Roof monitor" means that portion of the roof of a potroom where gases not captured at the cell exit from the potroom.

"Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.195 or by equivalent or alternative methods (see § 60.8(b)).

§ 60.192 Standards for fluorides.[114]

(a) On and after the date on which the initial performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases containing total fluorides, as measured according to § 60.8 above, in excess of

(1) 1.0 kg/Mg (2.0 lb/ton) of aluminum produced for potroom groups at Soderberg plants; except that emissions between 1.0 kg/Mg and 1.3 kg/Mg (2.6 lb/ton) will be considered in compliance if the owner or operator demonstrates that exemplary operation and maintenance procedures were used with respect to the emission control system and that proper control equipment was operating at the affected facility during the performance tests;

(2) 0.95 kg/Mg (1.9 lb/ton) of aluminum produced for potroom groups at prebake plants; except that emissions between 0.95 kg/Mg and 1.25 kg/Mg (2.5 lb/ton) will be considered in compliance if the owner or operator demonstrates that exemplary operation and maintenance procedures were used with respect to the emission control system and that proper control equipment was operating at the affected facility during the performance test; and

(3) 0.05 kg/Mg (0.1 lb/ton) of aluminum equivalent for anode bake plants.

(b) Within 30 days of any performance test which reveals emissions which fall between the 1.0 kg/Mg and 1.3 kg/Mg levels in paragraph (a)(1) of this section or between the 0.95 kg/Mg and 1.25 kg/Mg levels in paragraph (a)(2) of this section, the owner or operator shall submit a report indicating whether all necessary control devices were on-line and operating properly during the performance test, describing the operating and maintenance procedures followed, and setting forth any explanation for the excess emissions, to the Director of the Enforcement Division of the appropriate EPA Regional Office.

§ 60.193 Standard for visible emissions.[114]

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any potroom group any gases which exhibit 10 percent opacity or greater, or

(2) From any anode bake plant any gases which exhibit 20 percent opacity or greater.

§ 60.194 Monitoring of operations.[114]

(a) The owner or operator of any affected facility subject to the provisions of this subpart shall install, calibrate, maintain, and operate monitoring devices which can be used to determine daily the weight of aluminum and anode produced. The weighing devices shall have an accuracy of ± 5 percent over their operating range.

(b) The owner or operator of any affected facility shall maintain a record of daily production rates of aluminum and anodes, raw material feed rates, and cell or potline voltages.

(Section 114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 60.195 Test methods and procedures.[114]

(a) Following the initial performance test as required under § 60.8(a), an owner or operator shall conduct a performance test at least once each month during the life of the affected facility, except when malfunctions prevent representative sampling, as provided under § 60.8(c). The owner or operator shall give the Administrator at least 15 days advance notice of each test. The Administrator may require additional testing under section 114 of the Clean Air Act.

(b) An owner or operator may petition the Administrator to establish an alternative testing requirement that requires testing less frequently than once each month for a primary control system or an anode bake plant. If the owner or operator show that emissions from the primary control system or the anode bake plant have low variability during day-to-day operations, the Administrator may establish such an alternative testing requirement. The alternative testing requirement shall include a testing schedule and, in the case of a primary control system, the method to be used to determine primary control system emissions for the purpose of performance tests. The Administrator shall publish the alternative testing requirement in the **Federal Register**.

(c) Except as provided in § 60.8(b), reference methods specified in Appendix A of this part shall be used to determine compliance with the standards prescribed in § 60.192 as follows:

(1) For sampling emissions from stacks:

(i) Method 1 for sample and velocity traverses,

(ii) Method 2 for velocity and volumetric flow rate,

(iii) Method 3 for gas analysis, and

(iv) Method 13A or 13B for the concentration of total fluorides and the associated moisture content.

(2) For sampling emissions from roof monitors not employing stacks or pollutant collection systems:

(i) Method 1 for sample and velocity traverses,

(ii) Method 2 and Method 14 for

velocity and volumetric flow rate.

(iii) Method 3 for gas analysis, and

(iv) Method 14 for the concentration of total fluorides and associated moisture content.

(3) For sampling emissions from roof monitors not employing stacks but equipped with pollutant collection systems, the procedures under § 60.8(b) shall be followed.

(d) For Method 13A or 13B, the sampling time for each run shall be at least 8 hours for any potroom sample and at least 4 hours for any anode bake plant sample, and the minimum sample volume shall be 6.8 dscm (240 dscf) for any potroom sample and 3.4 dscm (120 dscf) for any anode bake plant sample except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(e) The air pollution control system for each affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined using applicable methods specified under paragraph (c) of this section.

(f) The rate of aluminum production is determined by dividing 720 hours into the weight of aluminum tapped from the affected facility during a period of 30 days prior to and including the final run of a performance test.

(g) For anode bake plants, the aluminum equivalent for anodes produced shall be determined as follows:

(1) Determine the average weight (Mg) of anode produced in anode bake plant during a representative oven cycle using a monitoring device which meets the requirements of § 60.194(a).

(2) Determine the average rate of anode production by dividing the total weight of anodes produced during the representative oven cycle by the length of the cycle in hours.

(3) Calculate the aluminum equivalent for anodes produced by multiplying the average rate of anode production by two. (Note: An owner or operator may establish a different multiplication factor by submitting production records of the Mg of aluminum produced and the concurrent Mg of anode consumed by potrooms.)

(h) For each run, potroom group emissions expressed in kg/Mg of aluminum produced shall be determined using the following equation:

$$Epg = \frac{(CsQs)_1 10^{-6} + (CsQs)_2 10^{-6}}{M}$$

Where:

Epg = potroom group emissions of total fluorides in kg/Mg of aluminum produced.

Cs = concentration of total fluorides in mg/dscm as determined by Method 13A or 13B, or by Method 14, as applicable.

Qs = volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2 and/or Method 14, as applicable

10^{-6} = conversion factor from mg to kg

M = rate of aluminum production in Mg/hr as determined by § 60.195(f).

$(CsQs)_1$ = product of Cs and Qs for measurements of primary control system effluent gas streams.

$(CsQs)_2$ = product of Cs and Qs for measurements of secondary control system or roof monitor effluent gas streams.

Where an alternative testing requirement has been established for the primary control system, the calculated value $(CsQs)_1$ from the most recent performance test will be used.

(i) For each run, as applicable, anode bake plant emissions expressed in kg/Mg of aluminum equivalent shall be determined using the following equation:

$$Ebp = \frac{CsQs\ 10^{-6}}{Me}$$

Where:

Ebp = anode bake plant emissions of total fluorides in kg/Mg of aluminum equivalent.

Cs = concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.

Qs = volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.

10^{-6} = conversion factor from mg to kg.

Me = aluminum equivalent for anodes produced by anode bake plants in Mg/hr as determined by § 60.195(g).

(Section 114 of the Clean Air Act as amended (42 U.S.C. 7414))

Proposed/effective
39 FR 37730, 10/23/74

Promulgated
41 FR 3825, 1/26/76 (27)

Revised
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)
45 FR 44202, 6/30/80 (114)

Subpart T—Standards of Performance for the Phosphate Fertilizer Industry: Wet-Process Phosphoric Acid Plants [14]

§ 60.200 Applicability and designation of affected facility. [64]

(a) The affected facility to which the provisions of this subpart apply is each wet-process phosphoric acid plant. For the purpose of this subpart, the affected facility includes any combination of: reactors, filters, evaporators, and hotwells.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 22, 1974, is subject to the requirements of this subpart.

§ 60.201 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Wet-process phosphoric acid plant" means any facility manufacturing phosphoric acid by reacting phosphate rock and acid.

(b) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.204, or equivalent or alternative methods.

(c) "Equivalent P_2O_5 feed" means the quantity of phosphorus, expressed as phosphorous pentoxide, fed to the process.

§ 60.202 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of 10.0 g/metric ton of equivalent P_2O_5 feed (0.020 lb/ton).

§ 60.203 Monitoring of operations.

(a) The owner or operator of any wet-process phosphoric acid plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a monitoring device which can be used to determine the mass flow of phosphorus-bearing feed material to the process. The monitoring device shall have an accuracy of ±5 percent over its operating range.

(b) The owner or operator of any wet-process phosphoric acid plant shall maintain a daily record of equivalent P_2O_5 feed by first determining the total mass rate in metric ton/hr of phosphorus bearing feed using a monitoring device for measuring mass flowrate which meets the requirements of paragraph (a) of this section and then by proceeding according to § 60.204(d)(2).

(c) The owner or operator of any wet-process phosphoric acid subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the process scrubbing system. The monitoring device shall have an accuracy of ±5 percent over its operating range.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68,83]

§ 60.204 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided in § 60.8 (b), shall be used to determine compliance with the standard prescribed in § 60.202 as follows:

(1) Method 13A or 13B for the concentration of total fluorides and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 13A or 13B, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for the affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined by applicable test methods and procedures.

(d) Equivalent P_2O_5 feed shall be determined as follows:

(1) Determine the total mass rate in metric ton/hr of phosphorus-bearing feed during each run using a flow monitoring device meeting the requirements of § 60.203(a).

(2) Calculate the equivalent P_2O_5 feed by multiplying the percentage P_2O_5 content, as measured by the spectrophotometric molybdovanadophosphate method (AOAC Method 9), times the total mass rate of phosphorus-bearing feed. AOAC Method 9 is published in the Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11–12. Other methods may be approved by the Administrator.

(e) For each run, emissions expressed in g/metric ton of equivalent P_2O_5 feed shall be determined using the following equation:

$$E = \frac{(C_s Q_s)\ 10^{-3}}{M_{P_2O_5}}$$

where:

E = Emissions of total fluorides in g/metric ton of equivalent P_2O_5 feed.

C_s = Concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.

Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.

10^{-3} = Conversion factor for mg to g.

$M_{P_2O_5}$ = Equivalent P_2O_5 feed in metric ton/hr as determined by § 60.204(d).

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68,83]

Proposed/effective
39 FR 37602, 10/22/74

Promulgated
40 FR 33152, 8/6/75 (14)

Revised
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart U—Standards of Performance for the Phosphate Fertilizer Industry: Superphosphoric Acid Plants [14]

§ 60.210 Applicability and designation of affected facility.[64]

(a) The affected facility to which the provisions of this subpart apply is each superphosphoric acid plant. For the purpose of this subpart, the affected facility includes any combination of: evaporators, hotwells, acid sumps, and cooling tanks.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 22, 1974, is subject to the requirements of this subpart.

§ 60.211 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Superphosphoric acid plant" means any facility which concentrates wet-process phosphoric acid to 66 percent or greater P_2O_5 content by weight for eventual consumption as a fertilizer.

(b) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.214, or equivalent or alternative methods.

(c) "Equivalent P_2O_5 feed" means the quantity of phosphorus, expressed as phosphorous pentoxide, fed to the process.

§ 60.212 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of 5.0 g/metric ton of equivalent P_2O_5 feed (0.010 lb/ton).

§ 60.213 Monitoring of operations.

(a) The owner or operator of any superphosphoric acid plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a flow monitoring device which can be used to determine the mass flow of phosphorus-bearing feed material to the process. The flow monitoring device shall have an accuracy of ± 5 percent over its operating range.

(b) The owner or operator of any superphosphoric acid plant shall maintain a daily record of equivalent P_2O_5 feed by first determining the total mass rate in metric ton/hr of phosphorus-bearing feed using a flow monitoring device meeting the requirements of paragraph (a) of this section and then by proceeding according to § 60.214(d)(2).

(c) The owner or operator of any superphosphoric acid plant subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the process scrubbing system. The monitoring device shall have an accuracy of ± 5 percent over its operating range.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68,83]

§ 60.214 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.212 as follows:

(1) Method 13A or 13B for the concentration of total fluorides and the associated moisture content.

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 13A or 13B, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be at least 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for the affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined by applicable test methods and procedures.

(d) Equivalent P_2O_5 feed shall be determined as follows:

(1) Determine the total mass rate in metric ton/hr of phosphorus-bearing feed during each run using a flow monitoring device meeting the requirements of § 60.213(a).

(2) Calculate the equivalent P_2O_5 feed by multiplying the percentage P_2O_5 content, as measured by the spectrophotometric molybdovanadophosphate method (AOAC Method 9), times the total mass rate of phosphorus-bearing feed. AOAC Method 9 is published in the Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11–12. Other methods may be approved by the Administrator.

(e) For each run, emissions expressed in g/metric ton of equivalent P_2O_5 feed, shall be determined using the following equation:

$$E = \frac{(C_s Q_s)\ 10^{-3}}{M_{P_2O_5}}$$

where:

E = Emissions of total fluorides in g/metric ton of equivalent P_2O_5 feed.

C_s = Concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.

Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.

10^{-3} = Conversion factor for mg to g.

$M_{P_2O_5}$ = Equivalent P_2O_5 feed in metric ton/hr as determined by § 60.214(d).

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68,83]

Proposed/effective
39 FR 37602, 10/22/74

Promulgated
40 FR 33152, 8/6/75 (14)

Revised
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart V—Standards of Performance for the Phosphate Fertilizer Industry: Diammonium Phosphate Plants [14]

§ 60.220 Applicability and designation of affected facility.[64]

(a) The affected facility to which the provisions of this subpart apply is each granular diammonium phosphate plant. For the purpose of this subpart, the affected facility includes any combination of: reactors, granulators, dryers, coolers, screens, and mills.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 22, 1974, is subject to the requirements of this subpart.

§ 60.221 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Granular diammonium phosphate plant" means any plant manufacturing granular diammonium phosphate by reacting phosphoric acid with ammonia.

(b) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.224, or equivalent or alternative methods.

(c) "Equivalent P_2O_5 feed" means the quantity of phosphorus, expressed as phosphorous pentoxide, fed to the process.

§ 60.222 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of 30 g/metric ton of equivalent P_2O_5 feed (0.060 lb/ton).

§ 60.223 Monitoring of operations.

(a) The owner or operator of any granular diammonium phosphate plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a flow monitoring device which can be used to determine the mass flow of phosphorus-bearing feed material to the process. The flow monitoring device shall have an accuracy of ±5 percent over its operating range.

(b) The owner or operator of any granular diammonium phosphate plant shall maintain a daily record of equivalent P_2O_5 feed by first determining the total mass rate in metric ton/hr of phosphorus-bearing feed using a flow monitoring device meeting the requirements of paragraph (a) of this section and then by proceeding according to § 60.224(d)(2).

(c) The owner or operator of any granular diammonium phosphate plant subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the scrubbing system. The monitoring device shall have an accuracy of ±5 percent over its operating range.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68,83]

§ 60.224 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.222 as follows:

(1) Method 13A or 13B for the concentration of total fluorides and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 13A or 13B, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be at least 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for the affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined by applicable test methods and procedures.

(d) Equivalent P_2O_5 feed shall be determined as follows:

(1) Determine the total mass rate in metric ton/hr of phosphorus-bearing feed during each run using a flow monitoring device meeting the requirements of § 60.223(a).

(2) Calculate the equivalent P_2O_5 feed by multiplying the percentage P_2O_5 content, as measured by the spectrophotometric molybdovanadophosphate method (AOAC Method 9), times the total mass rate of phosphorus-bearing feed. AOAC Method 9 is published in the Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11–12. Other methods may be approved by the Administrator.

(e) For each run, emissions expressed in g/metric ton of equivalent P_2O_5 feed shall be determined using the following equation:

$$E = \frac{(C_s Q_s)\ 10^{-3}}{M_{P_2O_5}}$$

where:

E = Emissions of total fluorides in g/metric ton of equivalent P_2O_5.

C_s = Concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.

Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.

10^{-3} = Conversion factor for mg to g.

$M_{P_2O_5}$ = Equivalent P_2O_5 feed in metric ton/hr as determined by § 60.224(d).

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68,83]

Proposed/effective
39 FR 37602, 10/24/74

Promulgated
40 FR 33152, 8/6/75 (14)

Revised
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart W—Standards of Performance for the Phosphate Fertilizer Industry: Triple Superphosphate Plants [14]

§ 60.230 Applicability and designation of affected facility.[64]

(a) The affected facility to which the provisions of this subpart apply is each triple superphosphate plant. For the purpose of this subpart, the affected facility includes any combination of: mixers, curing belts (dens), reactors, granulators, dryers, cookers, screens, mills, and facilities which store run-of-pile triple superphosphate.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 22, 1974, is subject to the requirements of this subpart.

§ 60.231 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Triple superphosphate plant" means any facility manufacturing triple superphosphate by reacting phosphate rock with phosphoric acid. A rule-of-pile triple superphosphate plant includes curing and storing.

(b) "Run-of-pile triple superphosphate" means any triple superphosphate that has not been processed in a granulator and is composed of particles at least 25 percent by weight of which (when not caked) will pass through a 16 mesh screen.

(c) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.234, or equivalent or alternative methods.

(d) "Equivalent P_2O_5 feed" means the quantity of phosphorus, expressed as phosphorus pentoxide, fed to the process.

§ 60.232 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of 100 g/metric ton of equivalent P_2O_5 feed (0.20 lb/ton).

§ 60.233 Monitoring of operations.

(a) The owner or operator of any triple superphosphate plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a flow monitoring device which can be used to determine the mass flow of phosphorus-bearing feed material to the process. The flow monitoring device shall have an accuracy of ±5 percent over its operating range.

(b) The owner or operator of any triple superphosphate plant shall maintain a daily record of equivalent P_2O_5 feed by first determining the total mass rate in metric ton/hr of phosphorus-bearing feed using a flow monitoring device meeting the requirements of paragraph (a) of this section and then by proceeding according to § 60.234(d)(2).

(c) The owner or operator of any triple superphosphate plant subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the process scrubbing system. The monitoring device shall have an accuracy of ±5 percent over its operating range.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.234 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.232 as follows:

(1) Method 13A or 13B for the concentration of total fluorides and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 13A or 13B, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be at least 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for the affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined by applicable test methods and procedures.

(d) Equivalent P_2O_5 feed shall be determined as follows:

(1) Determine the total mass rate in metric ton/hr of phosphorus-bearing feed during each run using a flow monitoring device meeting the requirements of § 60.233(a).

(2) Calculate the equivalent P_2O_5 feed by multiplying the percentage P_2O_5 content, as measured by the spectrophotometric molybdovanadophosphate method (AOAC Method 9), times the total mass rate of phosphorus-bearing feed. AOAC Method 9 is published in the Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11–12. Other methods may be approved by the Administrator.

(e) For each run, emissions expressed in g/metric ton of equivalent P_2O_5 feed shall be determined using the following equation:

$$E = \frac{(C_s Q_s)\ 10^{-3}}{M_{P_2O_5}}$$

where:

E = Emissions of total fluorides in g/metric ton of equivalent P_2O_5 feed.

C_s = Concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.

Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.

10^{-3} = Conversion factor for mg to g.

$M_{P_2O_5}$ = Equivalent P_2O_5 feed in metric ton/hr as determined by § 60.234(d).

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

Proposed/effective
39 FR 37602, 10/24/74

Promulgated
40 FR 33152, 8/6/75 (14)

Revised
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart X—Standards of Performance for the Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities [14]

§ 60.240 Applicability and designation of affected facility.[64]

(a) The affected facility to which the provisions of this subpart apply is each granular triple superphosphate storage facility. For the purpose of this subpart, the affected facility includes any combination of: storage or curing piles, conveyors, elevators, screens, and mills.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 22, 1974, is subject to the requirements of this subpart.

§ 60.241 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Granular triple superphosphate storage facility" means any facility curing or storing granular triple superphosphate.

(b) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.244, or equivalent or alternative methods.

(c) "Equivalent P_2O_5 stored" means the quantity of phosphorus, expressed as phosphorus pentoxide, being cured or stored in the affected facility.

(d) "Fresh granular triple superphosphate" means granular triple superphosphate produced no more than 10 days prior to the date of the performance test.

§ 60.242 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of 0.25 g/hr/metric ton of equivalent P_2O_5 stored (5.0×10^{-4} lb/hr/ton of equivalent P_2O_5 stored).

§ 60.243 Monitoring of operations.

(a) The owner or operator of any granular triple superphosphate storage facility subject to the provisions of this subpart shall maintain an accurate account of triple superphosphate in storage to permit the determination of the amount of equivalent P_2O_5 stored.

(b) The owner or operator of any granular triple superphosphate storage facility shall maintain a daily record of total equivalent P_2O_5 stored by multiplying the percentage P_2O_5 content, as determined by § 60.244(f)(2), times the total mass of granular triple superphosphate stored.

(c) The owner or operator of any granular triple superphosphate storage facility subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the process scrubbing sytem. The monitoring device shall have an accuracy of ±5 percent over its operating range.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.244 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.242 as follows:

(1) Method 13A or 13B for the concentration of total fluorides and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 13A or 13B, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be at least 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for the affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined by applicable test methods and procedures.

(d) Except as provided under paragraph (e) of this section, all performance tests on granular triple superphosphate storage facilities shall be conducted only when the following quantities of product are being cured or stored in the facility:

(1) Total granular triple superphosphate—at least 10 percent of the building capacity.

(2) Fresh granular triple superphosphate—at least 20 percent of the amount of triple superphosphate in the building.

(e) If the provisions set forth in paragraph (d)(2) of this section exceed production capabilities for fresh granular triple superphosphate, the owner or operator shall have at least five days maximum production of fresh granular triple superphosphate in the building during a performance test.

(f) Equivalent P_2O_5 stored shall be determined as follows:

(1) Determine the total mass stored during each run using an accountability system meeting the requirements of § 60.243(a).

(2) Calculate the equivalent P_2O_5 stored by multiplying the percentage P_2O_5 content, as measured by the spectrophotometric molybdovanadophosphate method (AOAC Method 9), times the total mass stored. AOAC Method 9 is published in the Afficial Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11-12. Other methods may be approved by the Administrator.

(g) For each run, emissions expressed in g/hr/metric ton of equivalent P_2O_5 stored shall be determined using the following equation:

$$E = \frac{(C_s Q_s)\ 10^{-3}}{M_{P_2O_5}}$$

where:

E = Emissions of total fluorides in g/hr/metric ton of equivalent P_2O_5 stored.

C_s = Concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.

Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.

10^{-3} = Conversion factor for mg to g.

$M_{P_2O_5}$ = Equivalent P_2O_5 feed in metric tons as measured by § 60.244(d).

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

Proposed/effective
39 FR 37602, 10/24/74

Promulgated
40 FR 33152, 8/6/75 (14)

Revised
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart Y—Standards of Performance for Coal Preparation Plants [26]

§ 60.250 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to any of the following affected facilities in coal preparation plants which process more than 200 tons per day: thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 24, 1974, is subject to the requirements of this subpart. [71]

§ 60.251 Definitions.

As used in this subpart, all terms not defined herein have the meaning given them in the Act and in subpart A of this part.

(a) "Coal preparation plant" means any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.

(b) "Bituminous coal" means solid fossil fuel classified as bituminous coal by A.S.T.M. Designation D–388–66.

(c) "Coal" means all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by A.S.T.M. Designation D–388–66.

(d) "Cyclonic flow" means a spiraling movement of exhaust gases within a duct or stack.

(e) "Thermal dryer" means any facility in which the moisture content of bituminous coal is reduced by contact with a heated gas stream which is exhausted to the atmosphere.

(f) "Pneumatic coal-cleaning equipment" means any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).

(g) "Coal processing and conveying equipment" means any machinery used to reduce the size of coal or to separate coal from refuse, and the equipment used to convey coal to or remove coal and refuse from the machinery. This includes, but is not limited to, breakers, crushers, screens, and conveyor belts.

(h) "Coal storage system" means any facility used to store coal except for open storage piles.

(i) "Transfer and loading system" means any facility used to transfer and load coal for shipment.

§ 60.252 Standards for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any thermal dryer gases which:

(1) Contain particulate matter in excess of 0.070 g/dscm (0.031 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any pneumatic coal cleaning equipment, gases which:

(1) Contain particulate matter in excess of 0.040 g/dscm (0.018 gr/dscf).

(2) Exhibit 10 percent opacity or greater.

(c) On and after the date on which the performance test required to be conducted by § 60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

§ 60.253 Monitoring of operations.

(a) The owner or operator of any thermal dryer shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(1) A monitoring device for the measurement of the temperature of the gas stream at the exit of the thermal dryer on a continuous basis. The monitoring device is to be certified by the manufacturer to be accurate within ±3° Fahrenheit.

(2) For affected facilities that use venturi scrubber emission control equipment:

(i) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gage.

(ii) A monitoring device for the continuous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply pressure. The pressure sensor or tap must be located close to the water discharge point. The Administrator may be consulted for approval of alternative locations.

(b) All monitoring devices under paragraph (a) of this section are to be recalibrated annually in accordance with procedures under § 60.13(b)(3) of this part.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

§ 60.254 Test methods and procedures.

(a) The reference methods in Appendix A of this part, except as provided in § 60.8(b), are used to determine compliance with the standards prescribed in § 60.252 as follows:

(1) Method 5 for the concentration of particulate matter and associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling time for each run is at least 60 minutes and the minimum sample volume is 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator. Sampling is not to be started until 30 minutes after start-up and is to be terminated before shutdown procedures commence. The owner or operator of the affected facility shall eliminate cyclonic flow during performance tests in a manner acceptable to the Administrator.

(c) The owner or operator shall construct the facility so that particulate emissions from thermal dryers or pneumatic coal cleaning equipment can be accurately determined by applicable test methods and procedures under paragraph (a) of this section.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

Proposed/effective
39 FR 37922, 10/24/74

Promulgated
41 FR 2231, 1/15/76 (26)

Revised
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
42 FR 44812, 9/7/77 (71)
43 FR 8800, 3/3/78 (83)

Subpart Z—Standards of Performance for Ferroalloy Production Facilities[33,35]

§ 60.260 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to the following affected facilities: electric submerged arc furnaces which produce silicon metal, ferrosilicon, calcium silicon, silicomanganese zirconium, ferrochrome silicon, silvery iron, high-carbon ferrochrome, charge chrome, standard ferromanganese, silicomanganese, ferromanganese silicon, or calcium carbide; and dust-handling equipment.[35]

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 21, 1974, is subject to the requirements of this subpart.

§ 60.261 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Electric submerged arc furnace" means any furnace wherein electrical energy is converted to heat energy by transmission of current between electrodes partially submerged in the furnace charge.

(b) "Furnace charge" means any material introduced into the electric submerged arc furnace and may consist of, but is not limited to, ores, slag, carbonaceous material, and limestone.

(c) "Product change" means any change in the composition of the furnace charge that would cause the electric submerged arc furnace to become subject to a different mass standard applicable under this subpart.

(d) "Slag" means the more or less completely fused and vitrified matter separated during the reduction of a metal from its ore.

(e) "Tapping" means the removal of slag or product from the electric submerged arc furnace under normal operating conditions such as removal of metal under normal pressure and movement by gravity down the spout into the ladle.

(f) "Tapping period" means the time duration from initiation of the process of opening the tap hole until plugging of the tap hole is complete.

(g) "Furnace cycle" means the time period from completion of a furnace product tap to the completion of the next consecutive product tap.

(h) "Tapping station" means that general area where molten product or slag is removed from the electric submerged arc furnace.

(i) "Blowing tap" means any tap in which an evolution of gas forces or projects jets of flame or metal sparks beyond the ladle, runner, or collection hood.[35]

(j) "Furnace power input" means the resistive electrical power consumption of an electric submerged arc furnace as measured in kilowatts.

(k) "Dust-handling equipment" means any equipment used to handle particulate matter collected by the air pollution control device (and located at or near such device) serving any electric submerged arc furnace subject to this subpart.

(l) "Control device" means the air pollution control equipment used to remove particulate matter generated by an electric submerged arc furnace from an effluent gas stream.

(m) "Capture system" means the equipment (including hoods, ducts, fans, dampers, etc.) used to capture or transport particulate matter generated by an affected electric submerged arc furnace to the control device.

(n) "Standard ferromanganese" means that alloy as defined by A.S.T.M. designation A99–66.

(o) "Silicomanganese" means that alloy as defined by A.S.T.M. designation A483–66.

(p) "Calcium carbide" means material containing 70 to 85 percent calcium carbide by weight.

(q) "High-carbon ferrochrome" means that alloy as defined by A.S.T.M. designation A101–66 grades HC1 through HC6.

(r) "Charge chrome" means that alloy containing 52 to 70 percent by weight chromium, 5 to 8 percent by weight carbon, and 3 to 6 percent by weight silicon.

(s) "Silvery iron" means any ferrosilicon, as defined by A.S.T.M. designation 100–69, which contains less than 30 percent silicon.

(t) "Ferrochrome silicon" means that alloy as defined by A.S.T.M. designation A482–66.

(u) "Silicomanganese zirconium" means that alloy containing 60 to 65 percent by weight silicon, 1.5 to 2.5 percent by weight calcium, 5 to 7 percent by weight zirconium, 0.75 to 1.25 percent by weight aluminum, 5 to 7 percent by weight manganese, and 2 to 3 percent by weight barium.

(v) "Calcium silicon" means that alloy as defined by A.S.T.M. designation A495–64.

(w) "Ferrosilicon" means that alloy as defined by A.S.T.M. designation A100–69 grades A, B, C, D, and E which contains 50 or more percent by weight silicon.

(x) "Silicon metal" means any silicon alloy containing more than 96 percent silicon by weight.

(y) "Ferromanganese silicon" means that alloy containing 63 to 66 percent by weight manganese, 28 to 32 percent by weight silicon, and a maximum of 0.08 percent by weight carbon.

§ 60.262 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any electric submerged arc furnace any gases which:

(1) Exit from a control device and contain particulate matter in excess of 0.45 kg/MW-hr (0.99 lb/MW-hr) while silicon metal, ferrosilicon, calcium silicon, or silicomanganese zirconium is being produced.

(2) Exit from a control device and contain particulate matter in excess of 0.23 kg/MW-hr (0.51 lb/MW-hr) while high-carbon ferrochrome, charge chrome, standard ferromanganese, silicomanganese, calcium carbide, ferrochrome silicon, ferromanganese silicon, or silvery iron is being produced.

(3) Exit from a control device and exhibit 15 percent opacity or greater.

(4) Exit from an electric submerged arc furnace and escape the capture system and are visible without the aid of instruments. The requirements under this subparagraph apply only during periods when flow rates are being established under § 60.265(d).

(5) Escape the capture system at the tapping station and are visible without the aid of instruments for more than 40 percent of each tapping period. There are no limitations on visible emissions under this subparagraph when a blowing tap occurs. The requirements under this subparagraph apply only during periods when flow rates are being established under § 60.265(d).

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any dust-handling equipment any gases which exhibit 10 percent opacity or greater.

§ 60.263 Standard for carbon monoxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any electric submerged arc furnace any gases which contain, on a dry basis, 20 or greater volume percent of carbon monoxide. Combustion of such gases under conditions acceptable to the Administrator constitutes compliance with this section. Acceptable conditions include, but are not limited to, flaring of gases or use of gases as fuel for other processes.

§ 60.264 Emission monitoring.

(a) The owner or operator subject to the provisions of this subpart shall install, calibrate, maintain and operate a continuous monitoring system for measurement of the opacity of emissions discharged into the atmosphere from the control device(s).

(b) For the purpose of reports required under § 60.7(c), the owner or operator shall report as excess emissions all six-minute periods in which the average opacity is 15 percent or greater.

(c) The owner or operator subject to the provisions of this subpart shall submit a written report of any product change to the Administrator. Reports of product changes must be postmarked not later than 30 days after implementation of the product change.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.265 Monitoring of operations.

(a) The owner or operator of any electric submerged arc furnace subject to the provisions of this subpart shall main-

tain daily records of the following information:

(1) Product being produced.

(2) Description of constituents of furnace charge, including the quantity, by weight.

(3) Time and duration of each tapping period and the identification of material tapped (slag or product.)

(4) All furnace power input data obtained under paragraph (b) of this section.

(5) All flow rate data obtained under paragraph (c) of this section or all fan motor power consumption and pressure drop data obtained under paragraph (e) of this section.

(b) The owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate a device to measure and continuously record the furnace power input. The furnace power input may be measured at the output or input side of the transformer. The device must have an accuracy of ±5 percent over its operating range.

(c) The owner or operator subject to the provisions of this subpart shall install, calibrate, and maintain a monitoring device that continuously measures and records the volumetric flow rate through each separately ducted hood of the capture system, except as provided under paragraph (e) of this section. The owner or operator of an electric submerged arc furnace that is equipped with a water cooled cover which is designed to contain and prevent escape of the generated gas and particulate matter shall monitor only the volumetric flow rate through the capture system for control of emissions from the tapping station. The owner or operator may install the monitoring device(s) in any appropriate location in the exhaust duct such that reproducible flow rate monitoring will result. The flow rate monitoring device must have an accuracy of ±10 percent over its normal operating range and must be calibrated according to the manufacturer's instructions. The Administrator may require the owner or operator to demonstrate the accuracy of the monitoring device relative to Methods 1 and 2 of Appendix A to this part.

(d) When performance tests are conducted under the provisions of § 60.8 of this part to demonstrate compliance with the standards under §§ 60.262(a)(4) and (5), the volumetric flow rate through each separately ducted hood of the capture system must be determined using the monitoring device required under paragraph (c) of this section. The volumetric flow rates must be determined for furnace power input levels at 50 and 100 percent of the nominal rated capacity of the electric submerged arc furnace. At all times the electric submerged arc furnace is operated, the owner or operator shall maintain the volumetric flow rate at or above the appropriate levels for that furnace power input level determined during the most recent performance test. If emissions due to tapping are captured and ducted separately from emissions of the electric submerged arc furnace, during each tapping period the owner or operator shall maintain the exhaust flow rates through the capture system over the tapping station at or above the levels established during the most recent performance test. Operation at lower flow rates may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. The owner or operator may request that these flow rates be reestablished by conducting new performance tests under § 60.8 of this part.

(e) The owner or operator may as an alternative to paragraph (c) of this section determine the volumetric flow rate through each fan of the capture system from the fan power consumption, pressure drop across the fan and the fan performance curve. Only data specific to the operation of the affected electric submerged arc furnace are acceptable for demonstration of compliance with the requirements of this paragraph. The owner or operator shall maintain on file a permanent record of the fan performance curve (prepared for a specific temperature) and shall:

(1) Install, calibrate, maintain, and operate a device to continuously measure and record the power consumption of the fan motor (measured in kilowatts), and

(2) Install, calibrate, maintain, and operate a device to continuously measure and record the pressure drop across the fan. The fan power consumption and pressure drop measurements must be synchronized to allow real time comparisons of the data. The monitoring devices must have an accuracy of ±5 percent over their normal operating ranges.

(f) The volumetric flow rate through each fan of the capture system must be determined from the fan power consumption, fan pressure drop, and fan performance curve specified under paragraph (e) of this section, during any performance test required under § 60.8 of this part to demonstrate compliance with the standards under §§ 60.262(a)(4) and (5). The owner or operator shall determine the volumetric flow rate at a representative temperature for furnace power input levels of 50 and 100 percent of the nominal rated capacity of the electric submerged arc furnace. At all times the electric submerged arc furnace is operated, the owner or operator shall maintain the fan power consumption and fan pressure drop at levels such that the volumetric flow rate is at or above the levels established during the most recent performance test for that furnace power input level. If emissions due to tapping are captured and ducted separately from emissions of the electric submerged arc furnace, during each tapping period the owner or operator shall maintain the fan power consumption and fan pressure drop at levels such that the volumetric flow rate is at or above the levels established during the most recent performance test. Operation at lower flow rates may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. The owner or operator may request that these flow rates be reestablished by conducting new performance tests under § 60.8 of this part. The Administrator may require the owner or operator to verify the fan performance curve by monitoring necessary fan operating parameters and determining the gas volume moved relative to Methods 1 and 2 of Appendix A to this part.

(g) All monitoring devices required under paragraphs (c) and (e) of this section are to be checked for calibration annually in accordance with the procedures under § 60.13(b).

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)), 68, 83

§ 60.266 *Test methods and procedures.*

(a) Reference methods in Appendix A of this part, except as provided in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.262 and § 60.263 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content except that the heating systems specified in paragraphs 2.1.2 and 2.1.4 of Method 5 are not to be used when the carbon monoxide content of the gas stream exceeds 10 percent by volume, dry basis.

(2) Method 1 for sample and velocity traverses.

(3) Method 2 for velocity and volumetric flow rate.

(4) Method 3 for gas analysis, including carbon monoxide.

(b) For Method 5, the sampling time for each run is to include an integral number of furnace cycles. The sampling time for each run must be at least 60 minutes and the minimum sample volume must be 1.8 dscm (64 dscf) when sampling emissions from open electric submerged arc furnaces with wet scrubber control devices, sealed electric submerged arc furnaces, or semi-enclosed electric submerged arc furnaces. When sampling emissions from other types of installations, the sampling time for each run must be at least 200 minutes and the minimum sample volume must be 5.7 dscm (200 dscf). Shorter sampling times or smaller sampling volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) During the performance test, the owner or operator shall record the maximum open hood area (in hoods with segmented or otherwise moveable sides) under which the process is expected to be operated and remain in compliance with all standards. Any future operation of the hooding system with open areas in excess of the maximum is not permitted.

(d) The owner or operator shall construct the control device so that volumetric flow rates and particulate matter emissions can be accurately determined by applicable test methods and procedures.

(e) During any performance test required under § 60.8 of this part, the owner or operator shall not allow gaseous diluents to be added to the effluent gas stream after the fabric in an open pressurized fabric filter collector unless the

total gas volume flow from the collector is accurately determined and considered in the determination of emissions.

(f) When compliance with § 60.263 is to be attained by combusting the gas stream in a flare, the location of the sampling site for particulate matter is to be upstream of the flare.

(g) For each run, particulate matter emissions, expressed in kg/hr (lb/hr), must be determined for each exhaust stream at which emissions are quantified using the following equation:

$$E_s = C_s Q_s$$

where:

E_s = Emissions of particulate matter in kg/hr (lb/hr).

C_s = Concentration of particulate matter in kg/dscm (lb/dscf) as determined by Method 5.

Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr (dscf/hr) as determined by Method 2.

(h) For Method 5, particulate matter emissions from the affected facility, expressed in kg/MW-hr (lb/MW-hr) must be determined for each run using the following equation:

$$E = \frac{\sum_{n=1}^{N} E_n}{p}$$ [35]

where:

E = Emissions of particulate from the affected facility, in kg/MW-hr (lb/MW-hr).

N = Total number of exhaust streams at which emissions are quantified.

E_n = Emission of particulate matter from each exhaust stream in kg/hr (lb/hr), as determined in paragraph (g) of this section.

p = Average furnace power input during the sampling period, in megawatts as determined according to § 60.263 (b).

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

Proposed/effective
39 FR 37922, 10/24/74

Promulgated
41 FR 18498, 5/4/76 (33)

Revised
41 FR 20659, 5/20/76 (35)
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
43 FR 8800, 3/3/78 (83)

Subpart AA—Standards of Performance for Steel Plants: Electric Arc Furnaces [16]

§ 60.270 Applicability and designation of affected facility.[64]

(a) The provisions of this subpart are applicable to the following affected facilities in steel plants: electric arc furnaces and dust-handling equipment.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 21, 1974, is subject to the requirements of this subpart.[71]

§ 60.271 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Electric arc furnace" (EAF) means any furnace that produces molten steel and heats the charge materials with electric arcs from carbon electrodes. Furnaces from which the molten steel is cast into the shape of finished products, such as in a foundry, are not affected facilities included within the scope of this definition. Furnaces which, as the primary source of iron, continuously feed prereduced ore pellets are not affected facilities within the scope of this definition.

(b) "Dust-handling equipment" means any equipment used to handle particulate matter collected by the control device and located at or near the control device for an EAF subject to this subpart.

(c) "Control device" means the air pollution control equipment used to remove particulate matter generated by an EAF(s) from the effluent gas stream.

(d) "Capture system" means the equipment (including ducts, hoods, fans, dampers, etc.) used to capture or transport particulate matter generated by an EAF to the air pollution control device.

(e) "Charge" means the addition of iron and steel scrap or other materials into the top of an electric arc furnace.

(f) "Charging period" means the time period commencing at the moment an EAF starts to open and ending either three minutes after the EAF roof is returned to its closed position or six minutes after commencement of opening of the roof, whichever is longer.

(g) "Tap" means the pouring of molten steel from an EAF.

(h) "Tapping period" means the time period commencing at the moment an EAF begins to tilt to pour and ending either three minutes after an EAF returns to an upright position or six minutes after commencing to tilt, whichever is longer.

(i) "Meltdown and refining" means that phase of the steel production cycle when charge material is melted and undesirable elements are removed from the metal.

(j) "Meltdown and refining period" means the time period commencing at the termination of the initial charging period and ending at the initiation of the tapping period, excluding any intermediate charging periods.

(k) "Shop opacity" means the arithmetic average of 24 or more opacity observations of emissions from the shop taken in accordance with Method 9 of Appendix A of this part for the applicable time periods.

(l) "Heat time" means the period commencing when scrap is charged to an empty EAF and terminating when the EAF tap is completed.

(m) "Shop" means the building which houses one or more EAF's.

(n) "Direct shell evacuation system" means any system that maintains a negative pressure within the EAF above the slag or metal and ducts these emissions to the control device.

§ 60.272 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from an electric arc furnace any gases which:

(1) Exit from a control device and contain particulate matter in excess of 12 mg/dscm (0.0052 gr/dscf).

(2) Exit from a control device and exhibit three percent opacity or greater.

(3) Exit from a shop and, due solely to operations of any EAF(s), exhibit greater than zero percent shop opacity except:

(i) Shop opacity greater than zero percent, but less than 20 percent, may occur during charging periods.

(ii) Shop opacity greater than zero percent, but less than 40 percent, may occur during tapping periods.

(iii) Opacity standards under paragraph (a)(3) of this section shall apply only during periods when flow rates and pressures are being established under § 60.274 (c) and (f).

(iv) Where the capture system is operated such that the roof of the shop is closed during the charge and the tap, and emissions to the atmosphere are prevented until the roof is opened after completion of the charge or tap, the shop opacity standards under paragraph (a)(3) of this section shall apply when the roof is opened and shall continue to apply for the length of time defined by the charging and/or tapping periods.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from dust-handling equipment any gases which exhibit 10 percent opacity or greater.

§ 60.273 Emission monitoring.

(a) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the control device(s) shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart.

(b) For the purpose of reports under § 60.7(c), periods of excess emissions that shall be reported are defined as all six-minute periods during which the average opacity is three percent or greater.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).[68, 83]

§ 60.274 Monitoring of operations.

(a) The owner or operator subject to the provisions of this subpart shall maintain records daily of the following information:

(1) Time and duration of each charge;

(2) Time and duration of each tap;

(3) All flow rate data obtained under paragraph (b) of this section, or equivalent obtained under paragraph (d) of this section; and

(4) All pressure data obtained under paragraph (e) of this section.

(b) Except as provided under paragraph (d) of this section, the owner or operator subject to the provisions of this subpart shall install, calibrate, and maintain a monitoring device that continously records the volumetric flow rate through each separately ducted hood. The monitoring device(s) may be installed in any appropriate location in the exhaust duct such that reproducible flow rate monitoring will result. The flow rate monitoring device(s) shall have an accuracy of ±10 percent over its normal operating range and shall be calibrated according to the manufacturer's instructions. The Administrator may require the owner or operator to demonstrate the accuracy of the monitoring device(s) relative to Methods 1 and 2 of Appendix A of this part.

(c) When the owner or operator of an EAF is required to demonstrate compliance with the standard under § 60.272 (a)(3) and at any other time the Administrator may require (under section 114 of the Act, as amended), the volumetric flow rate through each separately ducted hood shall be determined during all periods in which the hood is operated for the purpose of capturing emissions from the EAF using the monitoring device under paragraph (b) of this section. The owner or operator may petition the Administrator for reestablishment of these flow rates whenever the owner or operator can demonstrate to the Administrator's satisfaction that the EAF operating conditions upon which the flow rates were previously established are no longer applicable. The flow rates determined during the most recent demonstration of compliance shall be maintained (or may be exceeded) at the appropriate level for each applicable period. Operation at lower flow rates may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility.

(d) The owner or operator may petition the Administrator to approve any alternative method that will provide a continuous record of operation of each emission capture system.

(e) Where emissions during any phase of the heat time are controlled by use of a direct shell evacuation system, the

owner or operator shall install, calibrate, and maintain a monitoring device that continuously records the pressure in the free space inside the EAF. The pressure shall be recorded as 15-minute integrated averages. The monitoring device may be installed in any appropriate location in the EAF such that reproducible results will be obtained. The pressure monitoring device shall have an accuracy of ±5 mm of water gauge over its normal operating range and shall be calibrated according to the manufacturer's instructions.

(f) When the owner or operator of an EAF is required to demonstrate compliance with the standard under § 60.272 (a)(3) and at any other time the Administrator may require (under section 114 of the Act, as amended), the pressure in the free space inside the furnace shall be determined during the meltdown and refining period(s) using the monitoring device under paragraph (e) of this section. The owner or operator may petition the Administrator for reestablishment of the 15-minute integrated average pressure whenever the owner or operator can demonstrate to the Administrator's satisfaction that the EAF operating conditions upon which the pressures were previously established are no longer applicable. The pressure determined during the most recent demonstration of compliance shall be maintained at all times the EAF is operating in a meltdown and refining period. Operation at higher pressures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility.

(g) Where the capture system is designed and operated such that all emissions are captured and ducted to a control device, the owner or operator shall not be subject to the requirements of this section.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). 68 83

§ 60.275 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided under § 60.8(b), shall be used to determine compliance with the standards prescribed under § 60.272 as follows:

(1) Method 5 for concentration of particulate matter and associated moisture content;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling time for each run shall be at least four hours. When a single EAF is sampled, the sampling time for each run shall also include an integral number of heats. Shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator. The minimum sample volume shall be 4.5 dscm (160 dscf).

(c) For the purpose of this subpart, the owner or operator shall conduct the demonstration of compliance with 60.272(a)(3) and furnish the Administrator a written report of the results of the test.

(d) During any performance test required under § 60.8 of this part, no gaseous diluents may be added to the effluent gas stream after the fabric in any pressurized fabric filter collector, unless the amount of dilution is separately determined and considered in the determination of emissions.

(e) When more than one control device serves the EAF(s) being tested, the concentration of particulate matter shall be determined using the following equation:

$$C_s = \frac{\sum_{n=1}^{N} (C_s Q_s)_n}{\sum_{n=1}^{N} (Q_s)_n}$$

where:

C_s = concentration of particulate matter in mg/dscm (gr/dscf) as determined by method 5.

N = total number of control devices tested.

Q_s = volumetric flow rate of the effluent gas stream in dscm/hr (dscf/hr) as determined by method 2.

$(C_s Q_s)_n$ or $(Q_s)_n$ = value of the applicable parameter for each control device tested.

(f) Any control device subject to the provisions of this subpart shall be designed and constructed to allow measurement of emissions using applicable test methods and procedures.

(g) Where emissions from any EAF(s) are combined with emissions from facilities not subject to the provisions of this subpart but controlled by a common capture system and control device, the owner or operator may use any of the following procedures during a performance test:

(1) Base compliance on control of the combined emissions.

(2) Utilize a method acceptable to the Administrator which compensates for the emissions from the facilities not subject to the provisions of this subpart.

(3) Any combination of the criteria of paragraphs (g)(1) and (g)(2) of this section.

(h) Where emissions from any EAF(s) are combined with emissions from facilities not subject to the provisions of this subpart, the owner or operator may use any of the following procedures for demonstrating compliance with § 60.272 (a)(3):

(1) Base compliance on control of the combined emissions.

(2) Shut down operation of facilities not subject to the provisions of this subpart.

(3) Any combination of the criteria of paragraphs (h)(1) and (h)(2) of this section.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). 68 83

Proposed/effective
39 FR 37466, 10/21/74

Promulgated
40 FR 43850, 9/23/75 (16)

Revised
42 FR 37936, 7/25/77 (64)
42 FR 41424, 8/17/77 (68)
42 FR 44812, 9/7/77 (71)
43 FR 8800, 3/3/78 (83)

Subpart BB—Standards of Performance for Kraft Pulp Mills [82]

60.280 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in kraft pulp mills: digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, recovery furnace, smelt dissolving tank, lime kiln, and condensate stripper system. In pulp mills where kraft pulping is combined with neutral sulfite semichemical pulping, the provisions of this subpart are applicable when any portion of the material charged to an affected facility is produced by the kraft pulping operation.

(b) Any facility under paragraph (a) of this section that commences construction or modification after September 24, 1976, is subject to the requirements of this subpart.

§ 60.281 Definitions.

As used in this subpart, all terms not defined herein shall have the same meaning given them in the Act and in Subpart A.

(a) "Kraft pulp mill" means any stationary source which produces pulp from wood by cooking (digesting) wood chips in a water solution of sodium hydroxide and sodium sulfide (white liquor) at high temperature and pressure. Regeneration of the cooking chemicals through a recovery process is also considered part of the kraft pulp mill.

(b) "Neutral sulfite semichemical pulping operation" means any operation in which pulp is produced from wood by cooking (digesting) wood chips in a solution of sodium sulfite and sodium bicarbonate, followed by mechanical defibrating (grinding).

(c) "Total reduced sulfur (TRS)" means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide, that are released during the kraft pulping operation and measured by Reference Method 16.

(d) "Digester system" means each continuous digester or each batch digester used for the cooking of wood in white liquor, and associated flash tank(s), below tank(s), chip steamer(s), and condenser(s).

(e) "Brown stock washer system" means brown stock washers and associated knotters, vacuum pumps, and filtrate tanks used to wash the pulp following the digester system.

(f) "Multiple-effect evaporator system" means the multiple-effect evaporators and associated condenser(s) and hotwell(s) used to concentrate the spent cooking liquid that is separated from the pulp (black liquor).

(g) "Black liquor oxidation system" means the vessels used to oxidize, with air or oxygen, the black liquor, and associated storage tank(s).

(h) "Recovery furnace" means either a straight kraft recovery furnace or a cross recovery furnace, and includes the direct-contact evaporator for a direct-contact furnace.

(i) "Straight kraft recovery furnace" means a furnace used to recover chemicals consisting primarily of sodium and sulfur compounds by burning black liquor which on a quarterly basis contains 7 weight percent or less of the total pulp solids from the neutral sulfite semichemical process or has green liquor sulfidity of 28 percent or less.

(j) "Cross recovery furnace" means a furnace used to recover chemicals consisting primarily of sodium and sulfur compounds by burning black liquor which on a quarterly basis contains more than 7 weight percent of the total pulp solids from the neutral sulfite semichemical process and has a green liquor sulfidity of more than 28 percent.

(k) "Black liquor solids" means the dry weight of the solids which enter the recovery furnace in the black liquor.

(l) "Green liquor sulfidity" means the sulfidity of the liquor which leaves the smelt dissolving tank.

(m) "Smelt dissolving tank" means a vessel used for dissolving the smelt collected from the recovery furnace.

(n) "Lime kiln" means a unit used to calcine lime mud, which consists primarily of calcium carbonate, into quicklime, which is calcium oxide.

(o) "Condensate stripper system" means a column, and associated condensers, used to strip, with air or steam, TRS compounds from condensate streams from various processes within a kraft pulp mill.

§ 60.282 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any recovery furnace any gases which:

(i) Contain particulate matter in excess of 0.10 g/dscm (0.044 gr/dscf) corrected to 8 percent oxygen.

(ii) Exhibit 35 percent opacity or greater.

(2) From any smelt dissolving tank any gases which contain particulate matter in excess of 0.1 g/kg black liquor solids (dry weight)[0.2 lb/ton black liquor solids (dry weight)].

(3) From any lime kiln any gases which contain particulate matter in excess of:

(i) 0.15 g/dscm (0.067 gr/dscf) corrected to 10 percent oxygen, when gaseous fossil fuel is burned.

(ii) 0.30 g/dscm (0.13 gr/dscf) corrected to 10 percent oxygen, when liquid fossil fuel is burned.

§ 60.283 Standard for total reduced sulfur (TRS).

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system any gases which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to 10 percent oxygen, unless the following conditions are met:

(i) The gases are combusted in a lime kiln subject to the provisions of paragraph (a)(5) of this section; or

(ii) The gases are combusted in a recovery furnace subject to the provisions of paragraphs (a)(2) or (a)(3) of this section; or

(iii) The gases are combusted with other waste gases in an incinerator or other device, or combusted in a lime kiln or recovery furnace not subject to the provisions of this subpart, and are subjected to a minimum temperature of 1200° F. for at least 0.5 second; or

(iv) It has been demonstrated to the Administrator's satisfaction by the owner or operator that incinerating the exhaust gases from a new, modified, or reconstructed black liquor oxidation system or brown stock washer system in an existing facility is technologically or economically not feasible. Any exempt system will become subject to the provisions of this subpart if the facility is changed so that the gases can be incinerated.

(v) The gases from the digester system, brown stock washer system, condensate stripper system, or black liquor oxidation system are controlled by a means other than combustion. In this case, these systems shall not discharge any gases to the atmosphere which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to the actual oxygen content of the untreated gas stream.[91]

(2) From any straight kraft recovery furnace any gases which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to 8 percent oxygen.

(3) From any cross recovery furnace any gases which contain TRS in excess of 25 ppm by volume on a dry basis, corrected to 8 percent oxygen.

(4) From any smelt dissolving tank any gases which contain TRS in excess of 0.0084 g/kg black liquor solids (dry weight) [0.0168 lb/ton liquor solids (dry weight)].

(5) From any lime kiln any gases which contain TRS in excess of 8 ppm by volume on a dry basis, corrected to 10 percent oxygen.

§ 60.284 Monitoring of emissions and operations.

(a) Any owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate the following continuous monitoring systems:

(1) A continuous monitoring system to monitor and record the opacity of the gases discharged into the atmosphere from any recovery furnace. The span of this system shall be set at 70 percent opacity.

(2) Continuous monitoring systems to monitor and record the concentration of TRS emissions on a dry basis and the percent of oxygen by volume on a dry basis in the gases discharged into the atmosphere from any lime kiln, recovery furnace, digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system, except where the provisions of § 60.283(a)(1) (iii) or (iv) apply. These systems shall be located downstream of the control device(s) and the span(s) of these continuous monitoring system(s) shall be set:

(i) At a TRS concentration of 30 ppm for the TRS continuous monitoring system, except that for any cross recovery furnace the span shall be set at 50 ppm.

(ii) At 20 percent oxygen for the continuous oxygen monitoring system.

(b) Any owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate the following continuous monitoring devices:

(1) A monitoring device which measures the combustion temperature at the point of incineration of effluent gases which are emitted from any digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system where the provisions of § 60.283(a)(1)(iii) apply. The monitoring device is to be certified by the manufacturer to be accurate within ±1 percent of the temperature being measured.

(2) For any lime kiln or smelt dissolving tank using a scrubber emission control device:

(i) A monitoring device for the continuous measurement of the pressure loss of the gas stream through the control equipment. The monitoring device is to be certified by the manufacturer to be accurate to within a gage pressure of ±500 pascals (ca. ±2 inches water gage pressure).

(ii) A monitoring device for the continuous measurement of the scrubbing liquid supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±15 percent of design scrubbing liquid supply pressure. The pressure sensor or tap is to be located close to the scrubber liquid discharge point. The Administrator may be consulted for approval of alternative locations.

(c) Any owner or operator subject to the provisions of this subpart shall, except where the provisions of § 60.283(a)(1)(iv) or § 60.283(a)(4) apply.

(1) Calculate and record on a daily basis 12-hour average TRS concentrations for the two consecutive periods of each operating day. Each 12-hour average shall be determined as the arithmetic mean of the appropriate 12 contiguous 1-hour average total reduced sulfur concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section.

(2) Calculate and record on a daily basis 12-hour average oxygen concentrations for the two consecutive periods of each operating day for the recovery furnace and lime kiln. These 12-hour averages shall correspond to the 12-hour average TRS concentrations under paragraph (c)(1) of this section and shall be determined as an arithmetic mean of the appropriate 12 contiguous 1-hour average oxygen concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section.

(3) Correct all 12-hour average TRS concentrations to 10 volume percent oxygen, except that all 12-hour average TRS concentration from a recovery furnace shall be corrected to 8 volume percent using the following equation:

$$C_{corr} = C_{meas} \times (21 - X/21 - Y)$$

where:

C_{corr} = the concentration corrected for oxygen.

C_{meas} = the concentration uncorrected for oxygen.

X = the volumetric oxygen concentration in percentage to be corrected to (8 percent for recovery furnaces and 10 percent for lime kilns, incinerators, or other devices).

Y = the measured 12-hour average volumetric oxygen concentration.

(d) For the purpose of reports required under § 60.7(c), any owner or operator subject to the provisions of this subpart shall report periods of excess emissions as follows:

(1) For emissions from any recovery furnace periods of excess emissions are:

(i) All 12-hour averages of TRS concentrations above 5 ppm by volume for straight kraft recovery furnaces and above 25 ppm by volume for cross recovery furnaces.

(ii) All 6-minute average opacities that exceed 35 percent.

(2) For emissions from any lime kiln, periods of excess emissions are all 12-hour average TRS concentration above 8 ppm by volume.

(3) For emissions from any digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system periods of excess emissions are:

(i) All 12-hour average TRS concentrations above 5 ppm by volume unless the provisions of § 60.283(a)(1) (i), (ii), or (iv) apply; or

(ii) All periods in excess of 5 minutes and their duration during which the combustion temperature at the point of incineration is less than 1200° F. where the provisions of § 60.283(a)(1)(ii) apply.

(e) The Administrator will not consider periods of excess emissions reported under paragraph (d) of this section to be indicative of a violation of § 60.11(d) provided that:

(1) The percent of the total number of possible contiguous periods of excess emissions in a quarter (excluding periods of startup, shutdown, or malfunction and periods when the facility is not operating) during which excess emissions occur does not exceed:

(i) One percent for TRS emissions from recovery furnaces.

(ii) Six percent for average opacities from recovery furnaces.

(2) The Administrator determines that the affected facility, including air pollution control equipment, is maintained and operated in a manner which is consistent with good air pollution control practice for minimizing emissions during periods of excess emissions.

§ 60.285 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided under § 60.8(b), shall be used to determine compliance with § 60.282(a) as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) When determining compliance with § 60.282(a)(2), Method 2 for velocity and volumetric flow rate,

(4) Method 3 for gas analysis, and

(5) Method 9 for visible emissions.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.85 dscm/hr (0.53 dscf/min) except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator. Water shall be used as the cleanup solvent instead of acetone in the sample recovery procedure outlined in Method 5.

(c) Method 17 (in-stack filtration) may be used as an alternate method for Method 5 for determining compliance with § 60.282(a)(1)(i): *Provided*, That a constant value of 0.009 g/dscm (0.004 gr/dscf) is added to the results of Method 17 and the stack tempera-

ture is no greater than 205° C (ca. 400° F). Water shall be used as the cleanup solvent instead of acetone in the sample recovery procedure outlined in Method 17.

(d) For the purpose of determining compliance with § 60.283(a) (1), (2), (3), (4), and (5), the following reference methods shall be used:

(1) Method 16 for the concentration of TRS,

(2) Method 3 for gas analysis, and

(3) When determining compliance with § 60.283(a)(4), use the results of Method 2, Method 16, and the black liquor solids feed rate in the following equation to determine the TRS emission rate.

$$E = (C_{H_2S}F_{H_2S} + C_{MeSH}F_{MeSH} + C_{DMS}F_{DMS} + C_{DMDS}F_{DMDS})(Q_{sd})/BLS$$

Where:

E = mass of TRS emitted per unity of black liquor solids (g/kg) (lb/ton)

C_{H_2S} = average concentration of hydrogen sulfide (H_2S) during the test period, PPM.

C_{MeSH} = average concentration of methyl mercaptan (MeSH) during the test period, PPM.

C_{DMS} = average concentration of dimethyl sulfide (DMS) during the test period, PPM.

C_{DMDS} = average concentration of dimethyl disulfide (DMDS) during the test period, PPM.

F_{H_2S} = *0.001417 g/m³ PPM for metric units*
= 0.08844 lb/ft³ PPM for English units

F_{MeSH} = 0.00200 g/m³ PPM for metric units
= 0.1248 lb/ft³ PPM for English units

F_{DMS} = 0.002583 g/m³ PPM for metric units
= 0.1612 lb/ft³ PPM for English units

F_{DMDS} = 0.003917 g/m³ PPM for metric units
= 0.2445 lb/ft³ PPM for English units

Q_{sd} = dry volumetric stack gas flow rate corrected to standard conditions, dscm/hr (dscf/hr)

BLS = black liquor solids feed rate, kg/hr (lb/hr)

(4) When determining whether a furnace is straight kraft recovery furnace or a cross recovery furnace, TAPPI Method T.624 shall be used to determine sodium sulfide, sodium hydroxide and sodium carbonate. These determinations shall be made three times daily from the green liquor and the daily average values shall be converted to sodium oxide (Na_2O) and substituted into the following equation to determine the green liquor sulfidity:

$$GLS = 100\ C_{Na_2S}/C_{Na_2S} + C_{NaOH} + C_{Na_2CO_3}$$

Where:

GLS = percent green liquor sulfidity

C_{Na_2S} = average concentration of Na_2S expressed as Na_2O (mg/l)

C_{NaOH} = *average concentration of NaOH* expressed as Na_2O (mg/l)

$C_{Na_2CO_3}$ = average concentration of Na_2CO_3 expressed as Na_2O (mg/l)

(e) All concentrations of particulate matter and TRS required to be measured by this section from lime kilns or incinerators shall be corrected 10 volume percent oxygen and those concentrations from recovery furnaces shall be corrected to 8 volume percent oxygen. These corrections shall be made in the manner specified in § 60.284(c)(3).

Proposed/effective
41 FR 42012, 9/24/76

Promulgated
43 FR 7568, 2/23/78 (82)

Revised
43 FR 34784, 8/7/78 (91)

Subpart DD—Standards of Performance for Grain Elevators [90]

§ 60.300 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to each affected facility at any grain terminal elevator or any grain storage elevator, except as provided under § 60.304(b). The affected facilities are each truck unloading station, truck loading station, barge and ship unloading station, barge and ship loading station, railcar loading station, railcar unloading station, grain dryer, and all grain handling operations.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after (date of reinstatement of proposal) is subject to the requirements of this part.

§ 60.301 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the act and in subpart A of this part.

(a) "Grain" means corn, wheat, sorghum, rice, rye, oats, barley, and soybeans.

(b) "Grain elevator" means any plant or installation at which grain is unloaded, handled, cleaned, dried, stored, or loaded.

(c) "Grain terminal elevator" means any grain elevator which has a permanent storage capacity of more than 88,100 m^3 (ca. 2.5 million U.S. bushels), except those located at animal food manufacturers, pet food manufacturers, cereal manufacturers, breweries, and livestock feedlots.

(d) "Permanent storage capacity" means grain storage capacity which is inside a building, bin, or silo.

(e) "Railcar" means railroad hopper car or boxcar.

(f) "Grain storage elevator" means any grain elevator located at any wheat flour mill, wet corn mill, dry corn mill (human consumption), rice mill, or soybean oil extraction plant which has a permanent grain storage capacity of 35,200 m^3 (ca. 1 million bushels).

(g) "Process emission" means the particulate matter which is collected by a capture system.

(h) "Fugitive emission" means the particulate matter which is not collected by a capture system and is released directly into the atmosphere from an affected facility at a grain elevator.

(i) "Capture system" means the equipment such as sheds, hoods, ducts, fans, dampers, etc. used to collect particulate matter generated by an affected facility at a grain elevator.

(j) "Grain unloading station" means that portion of a grain elevator where the grain is transferred from a truck, railcar, barge, or ship to a receiving hopper.

(k) "Grain loading station" means that portion of a grain elevator where the grain is transferred from the elevator to a truck, railcar, barge, or ship.

(l) "Grain handling operations" include bucket elevators or legs (excluding legs used to unload barges or ships), scale hoppers and surge bins (garners), turn heads, scalpers, cleaners, trippers, and the headhouse and other such structures.

(m) "Column dryer" means any equipment used to reduce the moisture content of grain in which the grain flows from the top to the bottom in one or more continuous packed columns between two perforated metal sheets.

(n) "Rack dryer" means any equipment used to reduce the moisture content of grain in which the grain flows from the top to the bottom in a cascading flow around rows of baffles (racks).

(o) "Unloading leg" means a device which includes a bucket-type elevator which is used to remove grain from a barge or ship.

§ 60.302 Standard for particulate matter.

(a) On and after the 60th day of achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere any gases which exhibit greater than 0 percent opacity from any:

(1) Column dryer with column plate perforation exceeding 2.4 mm diameter (ca. 0.094 inch).

(2) Rack dryer in which exhaust gases pass through a screen filter coarser than 50 mesh.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility except a grain dryer any process emission which:

(1) Contains particulate matter in excess of 0.023 g/dscm (ca. 0.01 gr/dscf).

(2) Exhibits greater than 0 percent opacity.

(c) On and after the 60th day of achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere any fugitive emission from:

(1) Any individual truck unloading station, railcar unloading station, or railcar loading station, which exhibits greater than 5 percent opacity.

(2) Any grain handling operation which exhibits greater than 0 percent opacity.

(3) Any truck loading station which exhibits greater than 10 percent opacity.

(4) Any barge or ship loading station which exhibits greater than 20 percent opacity.

(d) The owner or operator of any barge or ship unloading station shall operate as follows:

(1) The unloading leg shall be enclosed from the top (including the receiving hopper) to the center line of the bottom pulley and ventilation to a control device shall be maintained on both sides of the leg and the grain receiving hopper.

(2) The total rate of air ventilated shall be at least 32.1 actual cubic meters per cubic meter of grain handling capacity (ca. 40 ft^3/bu).

(3) Rather than meet the requirements of subparagraphs (1) and (2), of this paragraph the owner or operator may use other methods of emission control if it is demonstrated to the Administrator's satisfaction that they would reduce emissions of particulate matter to the same level or less.

§ 60.303 Test methods and procedures.

(a) Reference methods in appendix A of this part, except as provided under § 60.8(b), shall be used to determine compliance with the standards prescribed under § 60.302 as follows:

(1) Method 5 or method 17 for concentration of particulate matter and associated moisture content;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate;

(4) Method 3 for gas analysis; and

(5) Method 9 for visible emissions.

(b) For method 5, the sampling probe and filter holder shall be operated without heaters. The sampling time for each run, using method 5 or method 17, shall be at least 60 minutes. The minimum sample volume shall be 1.7 dscm (ca. 60 dscf).

(Sec. 114, Clean Air Act, as amended (42 U.S.C. 7414).)

§ 60.304 Modifications.

(a) The factor 6.5 shall be used in place of "annual asset guidelines repair allowance percentage," to determine whether a capital expenditure as defined by § 60.2(bb) has been made to an existing facility.

(b) The following physical changes or changes in the method of operation shall not by themselves be considered a modification of any existing facility:

(1) The addition of gravity loadout spouts to existing grain storage or grain transfer bins.

(2) The installation of automatic grain weighing scales.

(3) Replacement of motor and drive units driving existing grain handling equipment.

(4) The installation of permanent storage capacity with no increase in hourly grain handling capacity.

Proposed/effective
43 FR 34349, 8/3/78

Promulgated
43 FR 34340, 8/3/78 (90)

Subpart GG—Standards of Performance for Stationary Gas Turbines [101]

§ 60.330 Applicability and designation of affected facility.

The provisions of this subpart are applicable to the following affected facilities: all stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour, based on the lower heating value of the fuel fired.

§ 60.331 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Stationary gas turbine" means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) "Simple cycle gas turbine" means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) "Regenerative cycle gas turbine" means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) "Combined cycle gas turbine" means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) "Emergency gas turbine" means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) "Ice fog" means an atmospheric suspension of highly reflective ice crystals.

(g) "ISO standard day conditions" means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) "Efficiency" means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) "Peak load" means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) "Base load" means the load level at which a gas turbine is normally operated.

(k) "Fire-fighting turbine" means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) "Turbines employed in oil/gas production or oil/gas transportation" means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A "Metropolitan Statistical Area" or "MSA" as defined by the Department of Commerce.

(n) "Offshore platform gas turbines" means any stationary gas turbine located on a platform in an ocean.

(o) "Garrison facility" means any permanent military installation.

(p) "Gas turbine model" means a group of gas turbines having the same nominal air flow, combuster inlet pressure, combuster inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

§ 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart, as specified in paragraphs (b), (c), and (d) of this section, shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), and (i) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined in part (3) of this paragraph.

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0150 \left(\frac{14.4}{Y}\right) + F$$

where:

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined in part (3) of this paragraph.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-Bound Nitrogen (percent by weight)	F (NO_x percent by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	$0.04(N)$
$0.1 < N \leq 0.25$	$0.004 + 0.0067(N-0.1)$
$N > 0.25$	0.005

where:

N = the nitrogen content of the fuel (percent by weight).

or:

Manufacturers may develop custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by § 60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the Federal Register.

(b) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired except as provided in § 60.332(d) shall comply with the provisions of § 60.332(a)(1).

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of § 60.332(a)(2).

(d) Stationary gas turbines employed in oil/gas production or oil/gas transportation and not located in Metropolitan Statistical Areas; and offshore platform turbines shall comply with the provisions of § 60.332(a)(2).

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have

commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NO_x emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

§ 60.333 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by § 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

§ 60.334 Monitoring of operations.

(a) The owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water injection to control NO_x emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within ±5.0 percent and shall be approved by the Administrator.

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

(c) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with § 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under § 60.335(a).

(2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

(3) *Ice fog.* Each period during which an exemption provided in § 60.332(g) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(Sec. 114 of the Clean Air Act as amended [42 U.S.C. 1857c-9]).

§ 60.335 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.332 as follows:

(1) Reference Method 20 for the concentration of nitrogen oxides and oxygen. For affected facilities under this subpart, the span value shall be 300 parts per million of nitrogen oxides.

(i) The nitrogen oxides emission level measured by Reference Method 20 shall be adjusted to ISO standard day conditions by the following ambient condition correction factor:

$$NO_x = (NO_{x_{obs}}) \left(\frac{P_{ref}}{P_{obs}}\right)^{0.5} e^{19(H_{obs} - 0.00633)} \left(\frac{T_{AMB}}{288°K}\right)^{1.53}$$

where:

NO_x = emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.

$NO_{x_{obs}}$ = measured NO_x emissions at 15 percent oxygen, ppmv.

P_{ref} = reference combuster inlet absolute pressure at 101.3 kilopascals ambient pressure.

P_{obs} = measured combustor inlet absolute pressure at test ambient pressure.

H_{obs} = specific humidity of ambient air at test.

e = transcendental constant (2.718).

T_{AMB} = temperature of ambient air at test.

The adjusted NO_x emission level shall be used to determine compliance with § 60.332.

(ii) Manufacturers may develop custom ambient condition correction factors for each gas turbine model they manufacture in terms of combustor inlet pressure, ambient air pressure, ambient air humidity and ambient air temperature to adjust the nitrogen oxides emission level measured by the performance test as provided for in § 60.8 to ISO standard day conditions. These ambient condition correction factors shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by § 60.8. Notices of approval of custom ambient condition correction factors will be published in the **Federal Register.**

(iii) The water-to-fuel ratio necessary to comply with § 60.332 will be determined during the initial performance test by measuring NO_x emission using Reference Method 20 and

the water-to-fuel ratio necessary to comply with § 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

(2) The analytical methods and procedures employed to determine the nitrogen content of the fuel being fired shall be approved by the Administrator and shall be accurate to within ±5 percent.

(b) The method for determining compliance with § 60.333, except as provided in § 60.8(b), shall be as follows:

(1) Reference Method 20 for the concentration of sulfur dioxide and oxygen or

(2) ASTM D2880–71 for the sulfur content of liquid fuels and ASTM D1072–70 for the sulfur content of gaseous fuels. These methods shall also be used to comply with § 60.334(b).

(c) Analysis for the purpose of determining the sulfur content and the nitrogen content of the fuel as required by § 60.334(b), this subpart, may be performed by the owner/operator, a service contractor retained by the owner/operator, the fuel vendor, or any other qualified agency provided that the analytical methods employed by these agencies comply with the applicable paragraphs of this section.

(Sec. 114 of the Clean Air Act as amended [42 U.S.C. 1857c–91]).

Proposed/effective
42 FR 53782, 10/3/77

Promulgated
44 FR 52792, 9/10/79 (101)

Subpart HH—Standards of Performance for Lime Manufacturing Plants [85]

§ 60.340 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities used in the manufacture of lime: rotary lime kilns and lime hydrators.

(b) The provisions of this subpart are not applicable to facilities used in the manufacture of lime at kraft pulp mills.

(c) Any facility under paragraph (a) of this section that commences construction or modification after May 3, 1977, is subject to the requirements of this part.

§ 60.341 Definitions.

As used in this subpart, all terms not defined herein shall have the same meaning given them in the Act and in subpart A of this part.

(a) "Lime manufacturing plant" includes any plant which produces a lime product from limestone by calcination. Hydration of the lime product is also considered to be part of the source.

(b) "Lime product" means the product of the calcination process including, but not limited to, calcitic lime, dolomitic lime, and dead-burned dolomite.

(c) "Rotary lime kiln" means a unit with an inclined rotating drum which is used to produce a lime product from limestone by calcination.

(d) "Lime hydrator" means a unit used to produce hydrated lime product.

§ 60.342 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any rotary lime kiln any gases which:

(i) Contain particulate matter in excess of 0.15 kilogram per megagram of limestone feed (0.30 lb/ton).

(ii) Exhibit 10 percent opacity or greater.

(2) From any lime hydrator any gases which contain particulate matter in excess of 0.075 kilogram per megagram of lime feed (0.15 lb/ton).

§ 60.343 Monitoring of emissions and operations.

(a) The owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate a continuous monitoring system, except as provided in paragraph (b) of this section, to monitor and record the opacity of a representative portion of the gases discharged into the atmosphere from any rotary lime kiln. The span of this system shall be set at 40 percent opacity.

(b) The owner or operator of any rotary lime kiln using a wet scrubbing emission control device subject to the provisions of this subpart shall not be required to monitor the opacity of the gases discharged as required in paragraph (a) of this section, but shall install, calibrate, maintain, and operate the following continuous monitoring devices:

(1) A monitoring device for the continuous measurement of the pressure loss of the gas stream through the scrubber. The monitoring device must be accurate within ±250 pascals (one inch of water).

(2) A monitoring device for the continuous measurement of the scrubbing liquid supply pressure to the control device. The monitoring device must be accurate within ±5 percent of design scrubbing liquid supply pressure.

(c) The owner or operator of any lime hydrator using a wet scrubbing emission control device subject to the provisions of this subpart shall install, calibrate, maintain, and operate the following continuous monitoring devices:

(1) A monitoring device for the continuous measuring of the scrubbing liquid flow rate. The monitoring device must be accurate within ±5 percent of design scrubbing liquid flow rate.

(2) A monitoring device for the continuous measurement of the electric current, in amperes, used by the scrubber. The monitoring device must be accurate within ±10 percent over its normal operating range.

(d) For the purpose of conducting a performance test under § 60.8, the owner or operator of any lime manufacturing plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a device for measuring the mass rate of limestone feed to any affected rotary lime kiln and the mass rate of lime feed to any affected lime hydrator. The measuring device used must be accurate to within ±5 percent of the mass rate over its operating range.

(e) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as all six-minute periods during which the average opacity of the plume from any lime kiln subject to paragraph (a) of this subpart is 10 percent or greater.

(Sec. 114 of the Clean Air Act, as amended (42 U.S.C. 7414).)

§ 60.344 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided under § 60.8(b), shall be used to determine compliance with § 60.322(a) as follows:

(1) Method 5 for the measurement of particulate matter,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate,

(4) Method 3 for gas analysis,

(5) Method 4 for stack gas moisture, and

(6) Method 9 for visible emissions.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.85 std m^3/h, dry basis (0.53 dscf/min), except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) Because of the high moisture content (40 to 85 percent by volume) of the exhaust gases from hydrators, the Method 5 sample train may be modified to include a calibrated orifice immediately following the sample nozzle when testing lime hydrators. In this configuration, the sampling rate necessary for maintaining isokinetic conditions can be directly related to exhaust gas velocity without a correction for moisture content. Extra care should be exercised when cleaning the sample train with the orifice in this position following the test runs.

(Sec. 114 of the Clean Air Act, as amended (42 U.S.C. 7414).)

Proposed/effective
42 FR 22506, 5/3/77

Promulgated
43 FR 9452, 3/7/78 (85)

The reference methods in this appendix are referred to in § 60.8 (Performance Tests) and § 60.11 (Compliance With Standards and Maintenance Requirements) of 40 CFR Part 60, Subpart A (General Provisions). Specific uses of these reference methods are described in the standards of performance contained in the subparts, beginning with Subpart D.

Within each standard of performance, a section titled "Test Methods and Procedures" is provided to (1) identify the test methods applicable to the facility subject to the respective standard and (2) identify any special instructions or conditions to be followed when applying a method to the respective facility. Such instructions (for example, establish sampling rates, volumes, or temperatures) are to be used either in addition to, or as a substitute for procedures in a reference method. Similarly, for sources subject to emission monitoring requirements, specific instructions pertaining to any use of a reference method are provided in the subpart or in Appendix B.

Inclusion of methods in this appendix is not intended as an endorsement or denial of their applicability to sources that are not subject to standards of performance. The methods are potentially applicable to other sources; however, applicability should be confirmed by careful and appropriate evaluation of the conditions prevalent at such sources.

The approach followed in the formulation of the reference methods involves specifications for equipment, procedures, and performance. In concept, a performance specification approach would be preferable in all methods because this allows the greatest flexibility to the user. In practice, however, this approach is impractical in most cases because performance specifications cannot be established. Most of the methods described herein, therefore, involve specific equipment specifications and procedures, and only a few methods in this appendix rely on performance criteria.

Minor changes in the reference methods should not necessarily affect the validity of the results and it is recognized that alternative and equivalent methods exist. Section 60.8 provides authority for the Administrator to specify or approve (1) equivalent methods, (2) alternative methods, and (3) minor changes in the methodology of the reference methods. It should be clearly understood that unless otherwise identified all such methods and changes must have prior approval of the Administrator. An owner employing such methods or deviations from the reference methods without obtaining prior approval does so at the risk of subsequent disapproval and retesting with approved methods.

Within the reference methods, certain specific equipment or procedures are recognized as being acceptable or potentially acceptable and are specifically identified in the methods. The items identified as acceptable options may be used without approval but must be identified in the test report. The potentially approvable options are cited as "subject to the approval of the Administrator" or as "or equivalent." Such potentially approvable techniques or alternatives may be used at the discretion of the owner without prior approval. However, detailed descriptions for applying these potentially approvable techniques or alternatives are not provided in the reference methods. Also, the potentially approvable options are not necessarily acceptable in all applications. Therefore, an owner electing to use such potentially approvable techniques or alternatives is responsible for: (1) assuring that the techniques or alternatives are in fact applicable and are properly executed; (2) including a written description of the alternative method in the test report (the written method must be clear and must be capable of being performed without additional instruction, and the degree of detail should be similar to the detail contained in the reference methods); and (3) providing any rationale or supporting data necessary to show the validity of the alternative in the particular application. Failure to meet these requirements can result in the Administrator's disapproval of the alternative.

69

METHOD 1 - SAMPLE AND VELOCITY TRAVERSES FOR STATIONARY SOURCES 69

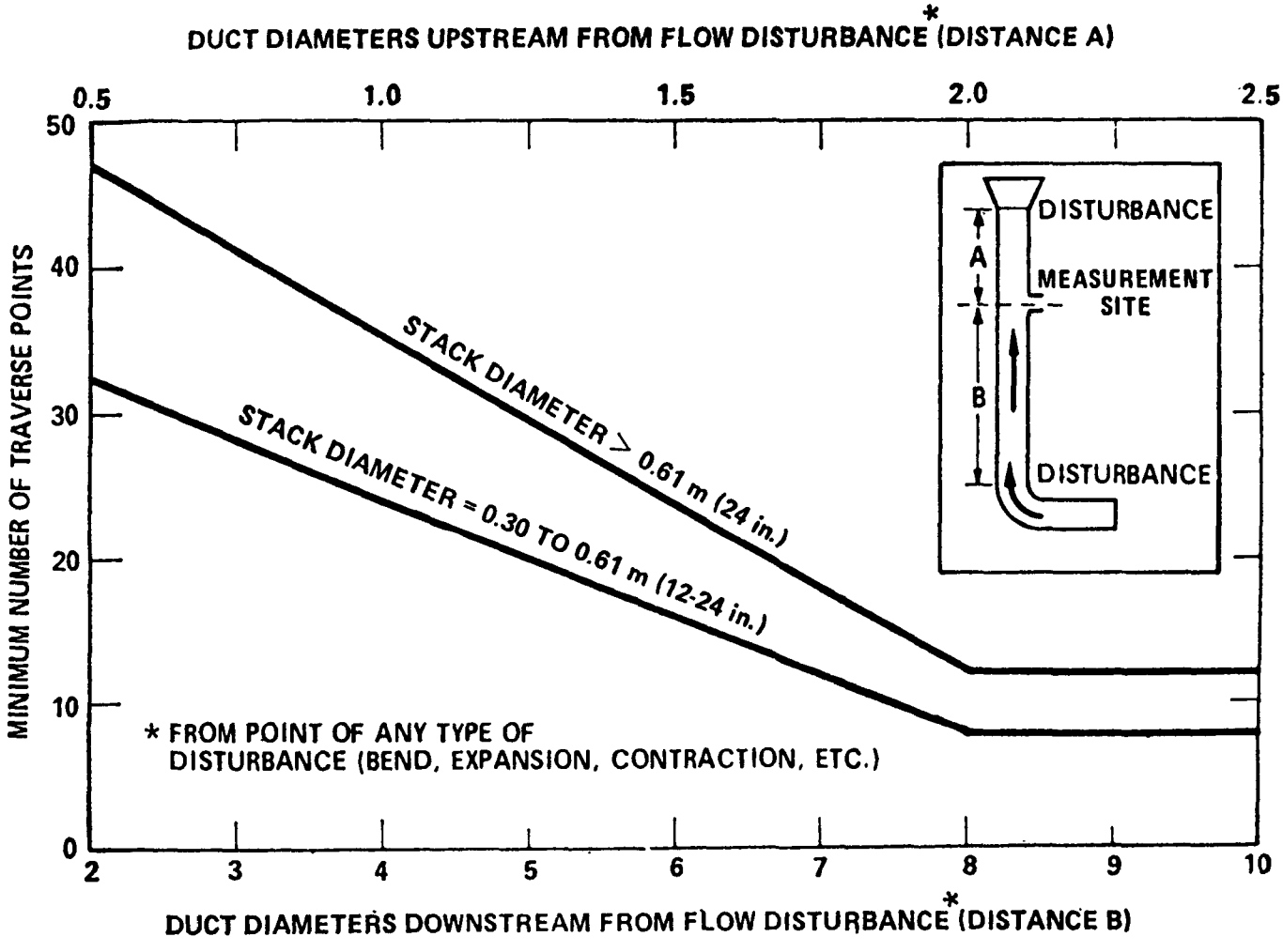


Figure 1-1. Minimum number of traverse points for particulate traverses.

1. *Principle and Applicability*

1.1 Principle. To aid in the representative measurement of pollutant emissions and/or total volumetric flow rate from a stationary source, a measurement site where the effluent stream is flowing in a known direction is selected, and the cross-section of the stack is divided into a number of equal areas. A traverse point is then located within each of these equal areas.

1.2 Applicability. This method is applicable to flowing gas streams in ducts, stacks, and flues. The method cannot be used when: (1) flow is cyclonic or swirling (see Section 2.4), (2) a stack is smaller than about 0.30 meter (12 in.) in diameter, or 0.071 m^2 (113 $in.^2$) in cross-sectional area, or (3) the measurement site is less than two stack or duct diameters downstream or less than a half diameter upstream from a flow disturbance.

The requirements of this method must be considered before construction of a new facility from which emissions will be measured; failure to do so may require subsequent alterations to the stack or deviation from the standard procedure. Cases involving variants are subject to approval by the Administrator, U.S. Environmental Protection Agency.

2. *Procedure*

2.1 Selection of Measurement Site. Sampling or velocity measurement is performed at a site located at least eight stack or duct diameters downstream and two diameters upstream from any flow disturbance such as a bend, expansion, or contraction in the stack, or from a visible flame. If necessary, an alternative location may be selected, at a position at least two stack or duct diameters downstream and a half diameter upstream from any flow disturbance. For a rectangular cross section, an equivalent diameter (D_e) shall be calculated from the following equation, to determine the upstream and downstream distances:

$$D_e = \frac{2LW}{L+W}$$

where L=length and W=width.

2.2 Determining the Number of Traverse Points.

2.2.1 Particulate Traverses. When the eight- and two-diameter criterion can be met, the minimum number of traverse points shall be: (1) twelve, for circular or rectangular stacks with diameters (or equivalent diameters) greater than 0.61 meter (24 in.); (2) eight, for circular stacks with diameters between 0.30 and 0.61 meter (12–24 in.); (3) nine, for rectangular stacks with equivalent diameters between 0.30 and 0.61 meter (12–24 in.).

When the eight- and two-diameter criterion cannot be met, the minimum number of traverse points is determined from Figure 1-1. Before referring to the figure, however, determine the distances from the chosen measurement site to the nearest upstream and downstream disturbances, and divide each distance by the stack diameter or equivalent diameter, to determine the distance in terms of the number of duct diameters. Then, determine from Figure 1-1 the minimum number of traverse points that corresponds: (1) to the number of duct diameters upstream; and (2) to the number of diameters downstream. Select the higher of the two minimum numbers of traverse points, or a greater value, so that for circular stacks the number is a multiple of 4, and for rectangular stacks, the number is one of those shown in Table 1-1.

TABLE 1-1. *Cross-sectional layout for rectangular stacks*

Number of traverse points: 87	*Matrix layout*
9	3x3
12	4x3
16	4x4
20	5x4
25	5x5
30	6x5
36	6x6
42	7x6
49	7x7

2.2.2 Velocity (Non-Particulate) Traverses. When velocity or volumetric flow rate is to be determined (but not particulate matter), the same procedure as that for particulate traverses (Section 2.2.1) is followed, except that Figure 1-2 may be used instead of Figure 1-1.

2.3 Cross-Sectional Layout and Location of Traverse Points.

2.3.1 Circular Stacks. Locate the traverse points on two perpendicular diameters according to Table 1-2 and the example shown in Figure 1-3. Any equation (for examples, see Citations 2 and 3 in the Bibliography) that gives the same values as those in Table 1-2 may be used in lieu of Table 1-2. 87

For particulate traverses, one of the diameters must be in a plane containing the greatest expected concentration variation, e.g., after bends, one diameter shall be in the plane of the bend. This requirement becomes less critical as the distance from the disturbance increases; therefore, other diameter locations may be used, subject to approval of the Administrator.

In addition, for stacks having diameters greater than 0.61 m (24 in.) no traverse points shall be located within 2.5 centimeters (1.00 in.) of the stack walls, and for stack diameters equal to or less than 0.61 m (24 in.), no traverse points shall be located within 1.3 cm (0.50 in.) of the stack walls. To meet these criteria, observe the procedures given below.

2.3.1.1 Stacks With Diameters Greater Than 0.61 m (24 in.). When any of the traverse points as located in Section 2.3.1 fall within 2.5 cm (1.00 in.) of the stack walls, relocate them away from the stack walls to: (1) a distance of 2.5 cm (1.00 in.); or (2) a distance equal to the nozzle inside diameter, whichever is larger. These relocated traverse points (on each end of a diameter) shall be the "adjusted" traverse points.

Whenever two successive traverse points are combined to form a single adjusted traverse point, treat the adjusted point as two separate traverse points, both in the sampling (or velocity measurement) procedure, and in recording the data.

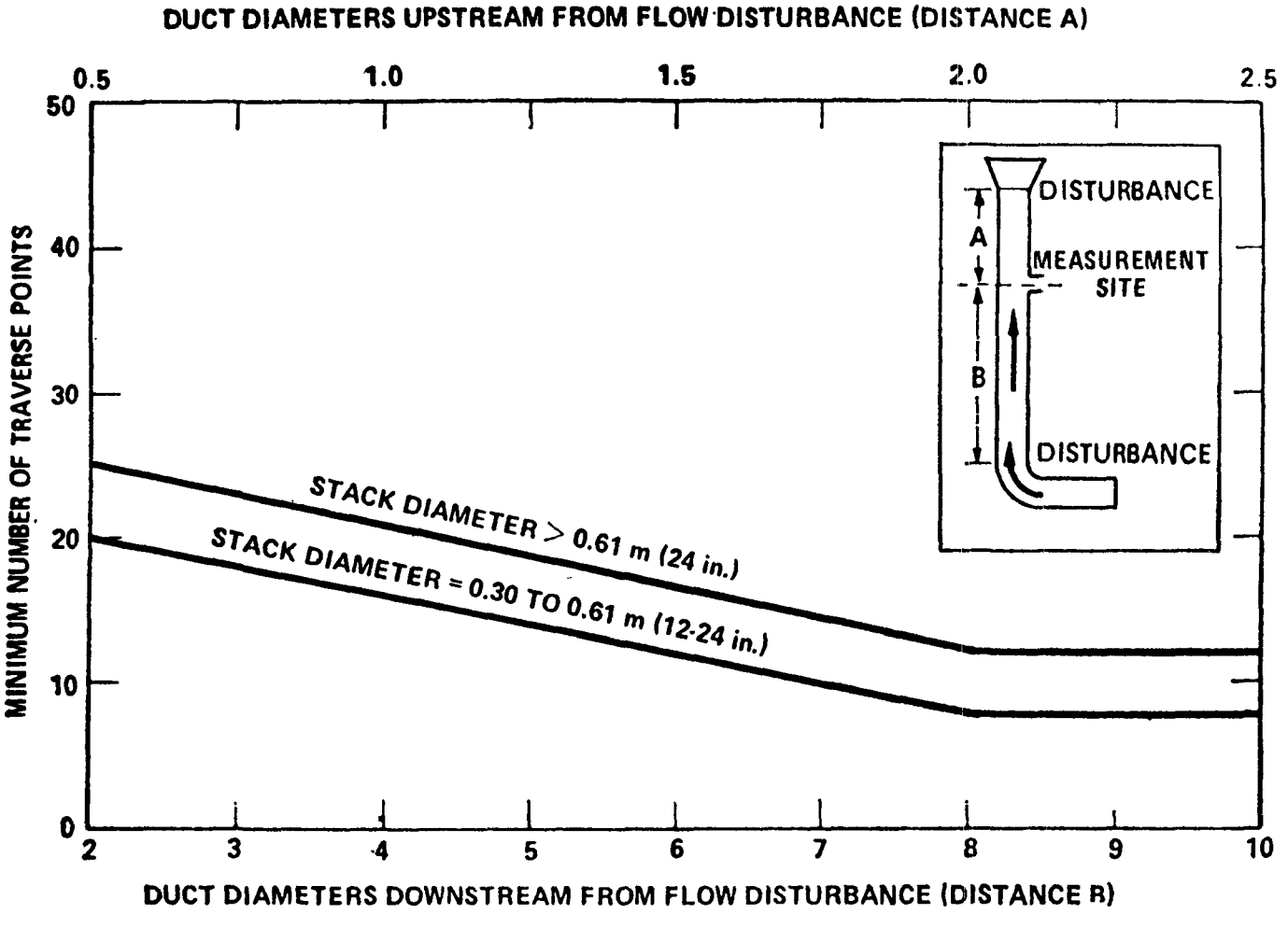


Figure 1-2. Minimum number of traverse points for velocity (nonparticulate) traverses.

TRAVERSE POINT	DISTANCE, % of diameter
1	4.4
2	14.7
3	29.5
4	70.5
5	85.3
6	95.6

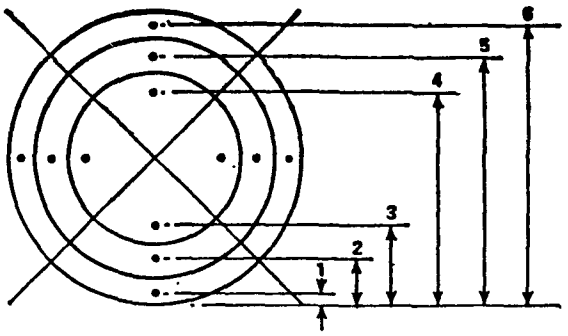


Figure 1-3. Example showing circular stack cross section divided into 12 equal areas, with location of traverse points indicated.

Table 1-2. LOCATION OF TRAVERSE POINTS IN CIRCULAR STACKS
(Percent of stack diameter from inside wall to traverse point)

Traverse point number on a diameter	Number of traverse points on a diameter											
	2	4	6	8	10	12	14	16	18	20	22	24
1	14.6	6.7	4.4	3.2	2.6	2.1	1.8	1.6	1.4	1.3	1.1	1.1
2	85.4	25.0	14.6	10.5	8.2	6.7	5.7	4.9	4.4	3.9	3.5	3.2
3		75.0	29.6	19.4	14.6	11.8	9.9	8.5	7.5	6.7	6.0	5.5
4		93.3	70.4	32.3	22.6	17.7	14.6	12.5	10.9	9.7	8.7	7.9
5			85.4	67.7	34.2	25.0	20.1	16.9	14.6	12.9	11.6	10.5
6			95.6	80.6	65.8	35.6	26.9	22.0	18.8	16.5	14.6	13.2
7				89.5	77.4	64.4	36.6	28.3	23.6	20.4	18.0	16.1
8				96.8	85.4	75.0	63.4	37.5	29.6	25.0	21.8	19.4
9					91.8	82.3	73.1	62.5	38.2	30.6	26.2	23.0
10					97.4	88.2	79.9	71.7	61.8	38.8	31.5	27.2
11						93.3	85.4	78.0	70.4	61.2	39.3	32.3
12						97.9	90.1	83.1	76.4	69.4	60.7	39.8
13							94.3	87.5	81.2	75.0	68.5	60.2
14							98.2	91.5	85.4	79.6	73.8	67.7
15								95.1	89.1	83.5	78.2	72.8
16								98.4	92.5	87.1	82.0	77.0
17									95.6	90.3	85.4	80.6
18									98.6	93.3	88.4	83.9
19										96.1	91.3	86.8
20										98.7	94.0	89.5
21											96.5	92.1
22											98.9	94.5
23												96.8
24												98.9

2.3.1.2 Stacks With Diameters Equal to or Less Than 0.61 m (24 in.). Follow the procedure in Section 2.3.1.1, noting only that any "adjusted" points should be relocated away from the stack walls to: (1) a distance of 1.3 cm (0.50 in.); or (2) a distance equal to the nozzle inside diameter, whichever is larger.

2.3.2 Rectangular Stacks. Determine the number of traverse points as explained in Sections 2.1 and 2.2 of this method. From Table 1-1, determine the grid configuration. Divide the stack cross-section into as many equal rectangular elemental areas as traverse points, and then locate a traverse point at the centroid of each equal area according to the example in Figure 1-4.

If the tester desires to use more than the minimum number of traverse points, expand the "minimum number of traverse points" matrix (see Table 1-1) by adding the extra traverse points along one or the other or both legs of the matrix; the final matrix need not be balanced. For example, if a 4x3 "minimum number of points" matrix were expanded to 36 points, the final matrix could be 9x4 or 12x3, and would not necessarily have to be 6x6. After constructing the final matrix, divide the stack cross-section into as many equal rectangular, elemental areas as traverse points, and locate a traverse point at the centroid of each equal area.[87]

The situation of traverse points being too close to the stack walls is not expected to arise with rectangular stacks. If this problem should ever arise, the Administrator must be contacted for resolution of the matter.

2.4 Verification of Absence of Cyclonic Flow. In most stationary sources, the direction of stack gas flow is essentially parallel to the stack walls. However, cyclonic flow may exist (1) after such devices as cyclones and inertial demisters following venturi scrubbers, or (2) in stacks having tangential inlets or other duct configurations which tend to induce swirling; in these instances, the presence or absence of cyclonic flow at the sampling location must be determined. The following techniques are acceptable for this determination.

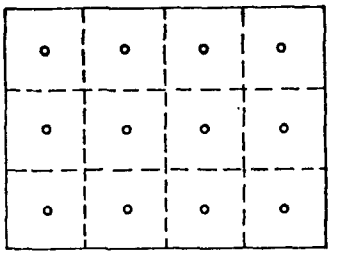


Figure 1-4. Example showing rectangular stack cross section divided into 12 equal areas, with a traverse point at centroid of each area.

Level and zero the manometer. Connect a Type S pitot tube to the manometer. Position the Type S pitot tube at each traverse point, in succession, so that the planes of the face openings of the pitot tube are perpendicular to the stack cross-sectional plane; when the Type S pitot tube is in this position, it is at "0° reference." Note the differential pressure (Δp) reading at each traverse point. If a null (zero) pitot reading is obtained at 0° reference at a given traverse point, an acceptable flow condition exists at that point. If the pitot reading is not zero at 0° reference, rotate the pitot tube (up to ±90° yaw angle), until a null reading is obtained. Carefully determine and record the value of the rotation angle (α) to the nearest degree. After the null technique has been applied at each traverse point, calculate the average of the absolute values of α; assign α values of 0° to those points for which no rotation was required, and include these in the overall average. If the average value of α is greater than 10°, the overall flow condition in the stack is unacceptable and alternative methodology, subject to the approval of the Administrator, must be used to perform accurate sample and velocity traverses.[87]

3. *Bibliography*

1. Determining Dust Concentration in a Gas Stream. ASME. Performance Test Code No. 27. New York. 1957.

2. Devorkin, Howard, et al. Air Pollution Source Testing Manual. Air Pollution Control District. Los Angeles, CA. November 1963

3. Methods for Determination of Velocity, Volume, Dust and Mist Content of Gases. Western Precipitation Division of Joy Manufacturing Co. Los Angeles, CA. Bulletin WP-50. 1968.

4. Standard Method for Sampling Stacks for Particulate Matter. In: 1971 Book of ASTM Standards, Part 23. ASTM Designation D-2928-71. Philadelphia, Pa. 1971.

5. Hanson, H. A., et al. Particulate Sampling Strategies for Large Power Plants Including Nonuniform Flow. USEPA, ORD, ESRL, Research Triangle Park, N.C. EPA-600/2-76-170. June 1976.

6. Entropy Environmentalists, Inc. Determination of the Optimum Number of Sampling Points: An Analysis of Method 1 Criteria. Environmental Protection Agency. Research Triangle Park, N.C. EPA Contract No. 68-01-3172, Task 7.

1. *Principle and Applicability*

1.1 Principle. The average gas velocity in a stack is determined from the gas density and from measurement of the average velocity head with a Type S (Stausscheibe or reverse type) pitot tube.

1.2 Applicability. This method is applicable for measurement of the average velocity of a gas stream and for quantifying gas flow.

This procedure is not applicable at measurement sites which fail to meet the criteria of Method 1, Section 2.1. Also, the method cannot be used for direct measurement in cyclonic or swirling gas streams, Section 2.4 of Method 1 shows how to determine cyclonic or swirling flow conditions. When unacceptable conditions exist, alternative procedures, subject to the approval of the Administrator, U.S. Environmental Protection Agency, must be employed to make accurate flow rate determinations; examples of such alternative procedures are: (1) to install straightening vanes; (2) to calculate the total volumetric flow rate stoichiometrically, or (3) to move to another measurement site at which the flow is acceptable.

2. *Apparatus*

Specifications for the apparatus are given below. Any other apparatus that has been demonstrated (subject to approval of the Administrator) to be capable of meeting the specifications will be considered acceptable.

2.1 Type S Pitot Tube. The Type S pitot tube (Figure 2-1) shall be made of metal tubing (e.g., stainless steel). It is recommended that the external tubing diameter (dimension D_t, Figure 2-2b) be between 0.48 and 0.95 centimeters ($\frac{3}{16}$ and $\frac{3}{4}$ inch). There shall be an equal distance from the base of each leg of the pitot tube to its face-opening plane (dimensions P_A and P_B, Figure 2-2b); it is recommended that this distance be between 1.05 and 1.50 times the external tubing diameter. The face openings of the pitot tube shall, preferably, be aligned as shown in Figure 2-2; however, slight misalignments of the openings are permissible (see Figure 2-3).

The Type S pitot tube shall have a known coefficient, determined as outlined in Section 4. An identification number shall be assigned to the pitot tube; this number shall be permanently marked or engraved on the body of the tube.

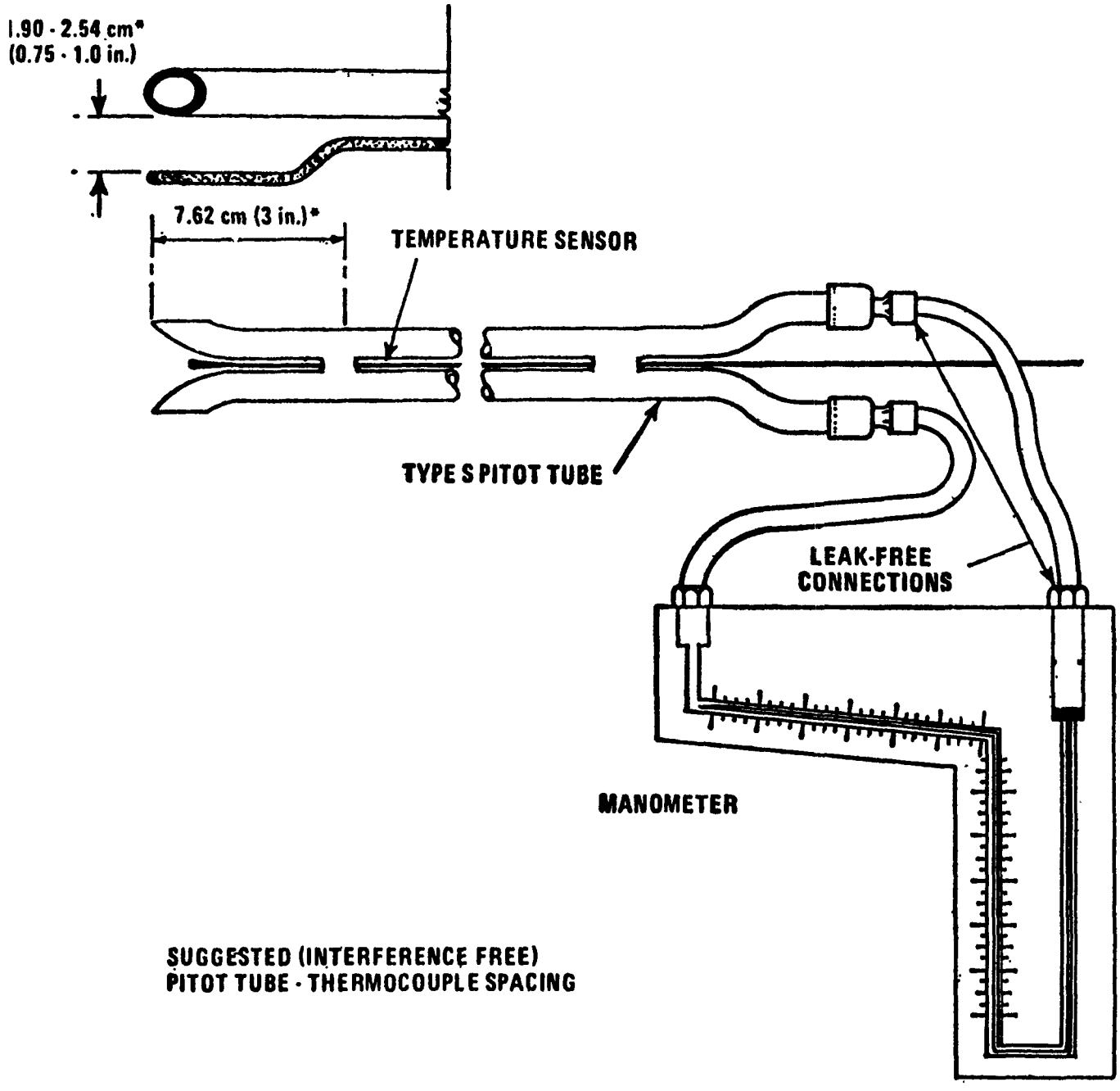


Figure 2-1. Type S pitot tube manometer assembly.

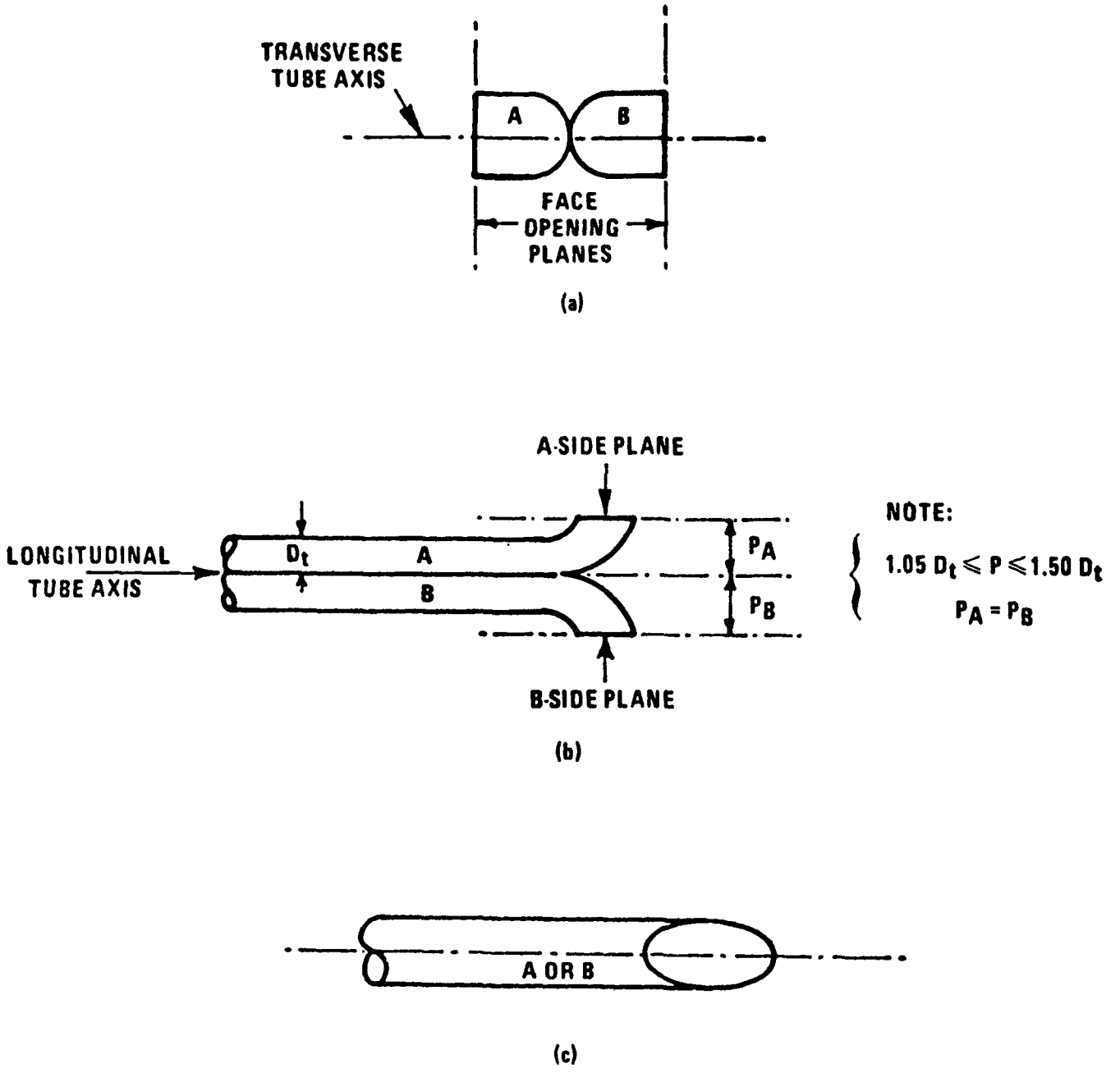


Figure 2-2. Properly constructed Type S pitot tube, shown in: (a) end view; face opening planes perpendicular to transverse axis; (b) top view; face opening planes parallel to longitudinal axis; (c) side view; both legs of equal length and centerlines coincident, when viewed from both sides. Baseline coefficient values of 0.84 may be assigned to pitot tubes constructed this way.

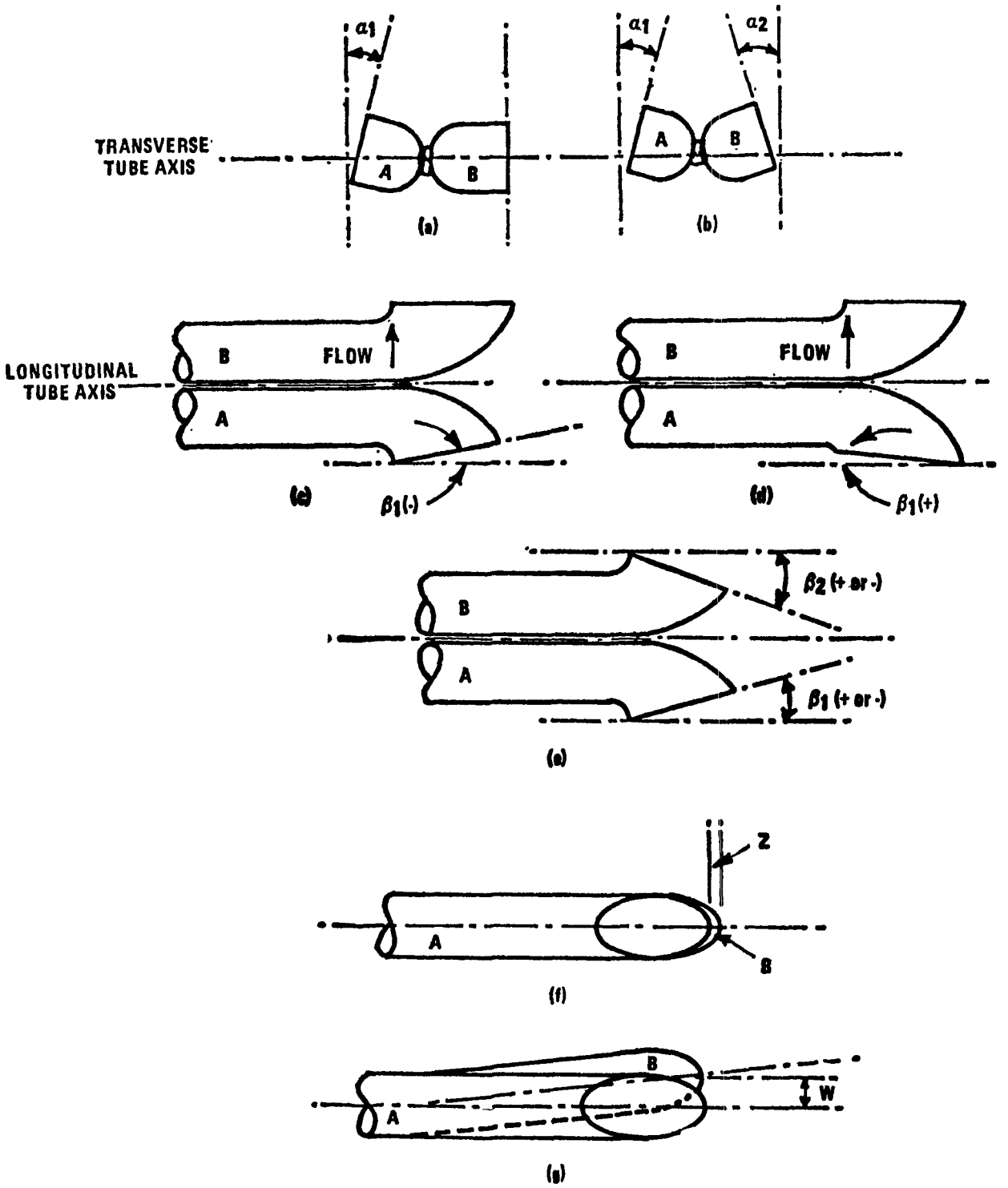


Figure 2-3. Types of face-opening misalignment that can result from field use or improper construction of Type S pitot tubes. These will not affect the baseline value of $\bar{C}p(s)$ so long as α_1 and $\alpha_2 < 10^o$, β_1 and $\beta_2 < 5^o$. $z < 0.32$ cm (1/8 in.) and $w <$ 0.08 cm (1/32 in.) (citation 11 in Section 6).

A standard pitot tube may be used instead of a Type S, provided that it meets the specifications of Sections 2.7 and 4.2; note, however, that the static and impact pressure holes of standard pitot tubes are susceptible to plugging in particulate-laden gas streams. Therefore, whenever a standard pitot tube is used to perform a traverse, adequate proof must be furnished that the openings of the pitot tube have not plugged up during the traverse period; this can be done by taking a velocity head (Δp) reading at the final traverse point, cleaning out the impact and static holes of the standard pitot tube by "back-purging" with pressurized air, and then taking another Δp reading. If the Δp readings made before and after the air purge are the same (±5 percent), the traverse is acceptable. Otherwise, reject the run. Note that if Δp at the final traverse point is unsuitably low, another point may be selected. If "back-purging" at regular intervals is part of the procedure, then comparative Δp readings shall be taken, as above, for the last two back purges at which suitably high Δp readings are observed.[87]

2.2 Differential Pressure Gauge. An inclined manometer or equivalent device is used. Most sampling trains are equipped with a 10-in. (water column) inclined-vertical manometer, having 0.01-in. H_2O divisions on the 0- to 1-in. inclined scale, and 0.1-in. H_2O divisions on the 1- to 10-in. vertical scale. This type of manometer (or other gauge of equivalent sensitivity) is satisfactory for the measurement of Δp values as low as 1.3 mm (0.05 in.) H_2O. However, a differential pressure gauge of greater sensitivity shall be used (subject to the approval of the Administrator), if any of the following is found to be true: (1) the arithmetic average of all Δp readings at the traverse points in the stack is less than 1.3 mm (0.05 in.) H_2O; (2) for traverses of 12 or more points, more than 10 percent of the individual Δp readings are below 1.3 mm (0.05 in.) H_2O; (3) for traverses of fewer than 12 points, more than one Δp reading is below 1.3 mm (0.05 in.) H_2O. Citation 18 in Section 6 describes commercially available instrumentation for the measurement of low-range gas velocities.[87]

As an alternative to criteria (1) through (3) above, the following calculation may be performed to determine the necessity of using a more sensitive differential pressure gauge.

$$T = \frac{\sum_{i=1}^{n} \sqrt{\Delta p_i + K}}{\sum_{i=1}^{n} \sqrt{\Delta p_i}}$$

where:

Δp_i = Individual velocity head reading at a traverse point, mm H_2O (in. H_2O).

n = Total number of traverse points.

K = 0.13 mm H_2O when metric units are used and 0.005 in H_2O when English units are used.

If T is greater than 1.05, the velocity head data are unacceptable and a more sensitive differential pressure gauge must be used.

NOTE.—If differential pressure gauges other than inclined manometers are used (e.g., magnehelic gauges), their calibration must be checked after each test series. To check the calibration of a differential pressure gauge, compare Δp readings of the gauge with those of a gauge-oil manometer at a minimum of three points, approximately representing the range of Δp values in the stack. If, at each point, the values of Δp as read by the differential pressure gauge and gauge-oil manometer agree to within 5 percent, the differential pressure gauge shall be considered to be in proper calibration. Otherwise, the test series shall either be voided, or procedures to adjust the measured Δp values and final results shall be used, subject to the approval of the Administrator.

2.3 Temperature Gauge. A thermocouple, liquid-filled bulb thermometer, bimetallic thermometer, mercury-in-glass thermometer, or other gauge capable of measuring temperature to within 1.5 percent of the minimum absolute stack temperature shall be used. The temperature gauge shall be attached to the pitot tube such that the sensor tip does not touch any metal; the gauge shall be in an interference-free arrangement with respect to the pitot tube face openings (see Figure 2-1 and also Figure 2-7 in Section 4). Alternate positions may be used if the pitot tube-temperature gauge system is calibrated according to the procedure of Section 4. Provided that a difference of not more than 1 percent in the average velocity measurement is introduced, the temperature gauge need not be attached to the pitot tube; this alternative is subject to the approval of the Administrator.

2.4 Pressure Probe and Gauge. A piezometer tube and mercury- or water-filled U-tube manometer capable of measuring stack pressure to within 2.5 mm (0.1 in.) Hg is used. The static tap of a standard type pitot tube or one leg of a Type S pitot tube with the face opening planes positioned parallel to the gas flow may also be used as the pressure probe.[87]

2.5 Barometer. A mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg) may be used. In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and the sampling point shall be applied at a rate of minus 2.5 mm (0.1 in.) Hg per 30-meter (100 foot) elevation increase, or vice-versa for elevation decrease.

2.6 Gas Density Determination Equipment. Method 3 equipment, if needed (see Section 3.6), to determine the stack gas dry molecular weight, and Reference Method 4 or Method 5 equipment for moisture content determination; other methods may be used subject to approval of the Administrator.

2.7 Calibration Pitot Tube. When calibration of the Type S pitot tube is necessary (see Section 4), a standard pitot tube is used as a reference. The standard pitot tube shall, preferably, have a known coefficient, obtained either (1) directly from the National Bureau of Standards, Route 270, Quince Orchard Road, Gaithersburg, Maryland, or (2) by calibration against another standard pitot tube with an NBS-traceable coefficient. Alternatively, a standard pitot tube designed according to the criteria given in 2.7.1 through 2.7.5 below and illustrated in Figure 2-4 (see also Citations 7, 8, and 17 in Section 6) may be used. Pitot tubes designed according to these specifications will have baseline coefficients of about 0.99±0.01.

2.7.1 Hemispherical (shown in Figure 2-4), ellipsoidal, or conical tip.

2.7.2 A minimum of six diameters straight run (based upon D, the external diameter of the tube) between the tip and the static pressure holes.

2.7.3 A minimum of eight diameters straight run between the static pressure holes and the centerline of the external tube, following the 90 degree bend.

2.7.4 Static pressure holes of equal size (approximately 0.1 D), equally spaced in a piezometer ring configuration.

2.7.5 Ninety degree bend, with curved or mitered junction.

2.8 Differential Pressure Gauge for Type S Pitot Tube Calibration. An inclined manometer or equivalent is used. If the single-velocity calibration technique is employed (see Section 4.1.2.3), the calibration differential pressure gauge shall be readable to the nearest 0.13 mm H_2O (0.005 in. H_2O). For multivelocity calibrations, the gauge shall be readable to the nearest 0.13 mm H_2O (0.005 in H_2O) for Δp values between 1.3 and 25 mm H_2O (0.05 and 1.0 in. H_2O), and to the nearest 1.3 mm H_2O (0.05 in. H_2O) for Δp values above 25 mm H_2O (1.0 in. H_2O). A special, more sensitive gauge will be required to read Δp values below 1.3 mm H_2O [0.05 in. H_2O] (see Citation 18 in Section 6).

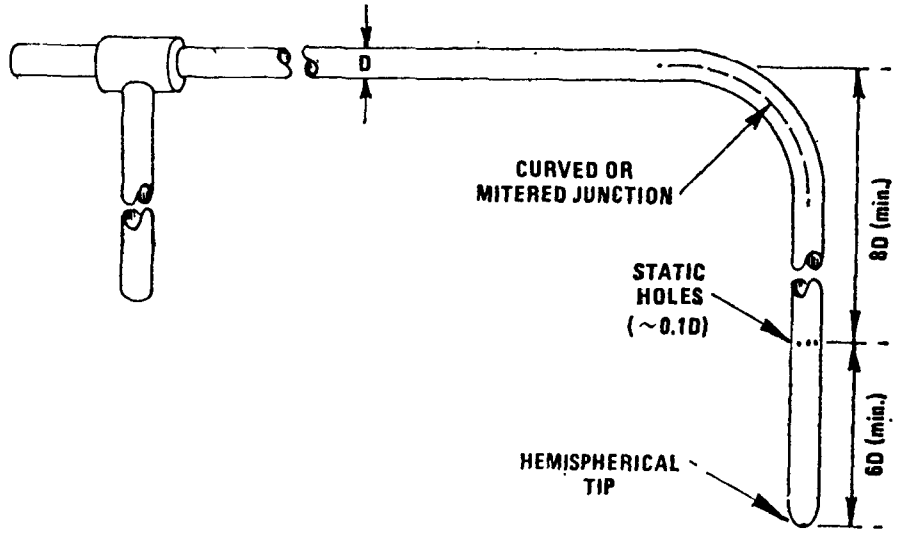


Figure 2-4. Standard pitot tube design specifications.

3. *Procedure*

3.1 Set up the apparatus as shown in Figure 2-1. Capillary tubing or surge tanks installed between the manometer and pitot tube may be used to dampen Δp fluctuations. It is recommended, but not required, that a pretest leak-check be conducted, as follows: (1) blow through the pitot impact opening until at least 7.6 cm (3 in.) H_2O velocity pressure registers on the manometer; then, close off the impact opening. The pressure shall remain stable for at least 15 seconds; (2) do the same for the static pressure side, except using suction to obtain the minimum of 7.6 cm (3 in.) H_2O. Other leak-check procedures, subject to the approval of the Administrator, may be used.

3.2 Level and zero the manometer. Because the manometer level and zero may drift due to vibrations and temperature changes, make periodic checks during the traverse. Record all necessary data as shown in the example data sheet (Figure 2-5).[87]

3.3 Measure the velocity head and temperature at the traverse points specified by Method 1. Ensure that the proper differential pressure gauge is being used for the range of Δp values encountered (see Section 2.2). If it is necessary to change to a more sensitive gauge, do so, and remeasure the Δp and temperature readings at each traverse point. Conduct a post-test leak-check (mandatory), as described in Section 3.1 above, to validate the traverse run.

3.4 Measure the static pressure in the stack. One reading is usually adequate.

3.5 Determine the atmospheric pressure.

PLANT _____

DATE _____ RUN NO. _____

STACK DIAMETER OR DIMENSIONS, m(in.) _____

BAROMETRIC PRESSURE, mm Hg (in. Hg) _____

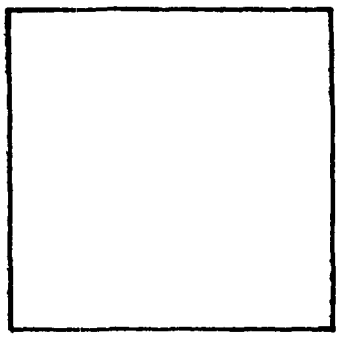
CROSS SECTIONAL AREA, $m^2(ft^2)$ _____

OPERATORS _____

PITOT TUBE I.D. NO. _____

AVG. COEFFICIENT, C_p = _____

LAST DATE CALIBRATED _____



SCHEMATIC OF STACK CROSS SECTION

Traverse Pt. No.	Vel. Hd., Δp mm (in.) H_2O	Stack Temperature		P_g mm Hg (in.Hg)	$\sqrt{\Delta p}$
		t_s, °C (°F)	T_s, °K (°R)		
		Average			

Figure 2-5. Velocity traverse data.

3.6 Determine the stack gas dry molecular weight. For combustion processes or processes that emit essentially CO_2, O_2, CO, and N_2, use Method 3. For processes emitting essentially air, an analysis need not be conducted; use a dry molecular weight of 29.0. For other processes, other methods, subject to the approval of the Administrator, must be used.

3.7 Obtain the moisture content from Reference Method 4 (or equivalent) or from Method 5.

3.8 Determine the cross-sectional area of the stack or duct at the sampling location. Whenever possible, physically measure the stack dimensions rather than using blueprints.

4 *Calibration*

4.1 Type S Pitot Tube. Before its initial use, carefully examine the Type S pitot tube in top, side, and end views to verify that the face openings of the tube are aligned within the specifications illustrated in Figure 2-2 or 2-3. The pitot tube shall not be used if it fails to meet these alignment specifications.

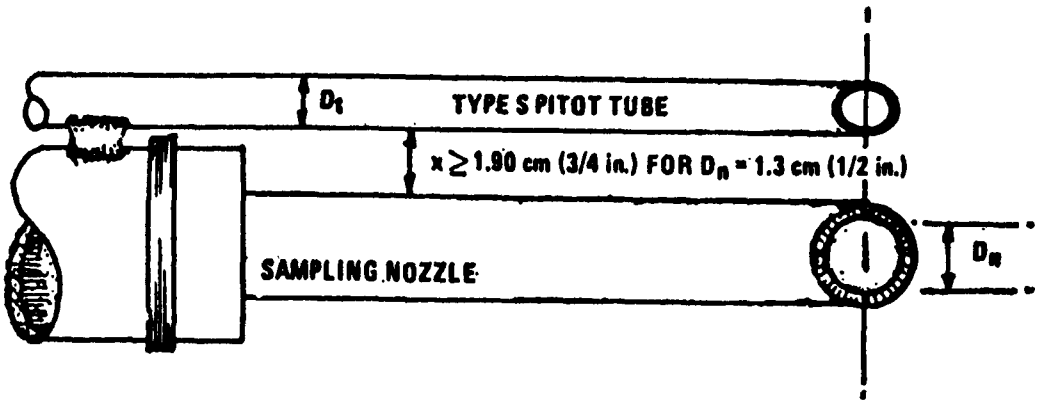
After verifying the face opening alignment, measure and record the following dimensions of the pitot tube: (a) the external tubing diameter (dimension D_t, Figure 2-2b); and (b) the base-to-opening plane distances (dimensions P_A and P_B, Figure 2-2b). If D_t is between 0.48 and 0.95 cm (3/16 and 3/8 in.) and if P_A and P_B are equal and between 1.05 and 1.50 D_t, there are two possible options: (1) the pitot tube may be calibrated according to the procedure outlined in Sections 4.1.2 through 4.1.5 below, or (2) a baseline (isolated tube) coefficient value of 0.84 may be assigned to the pitot tube. Note, however, that if the pitot tube is part of an assembly, calibration may still be required, despite knowledge of the baseline coefficient value (see Section 4.1.1).[87]

If D_t, P_A, and P_B are outside the specified limits, the pitot tube must be calibrated as outlined in 4.1.2 through 4.1.5 below.

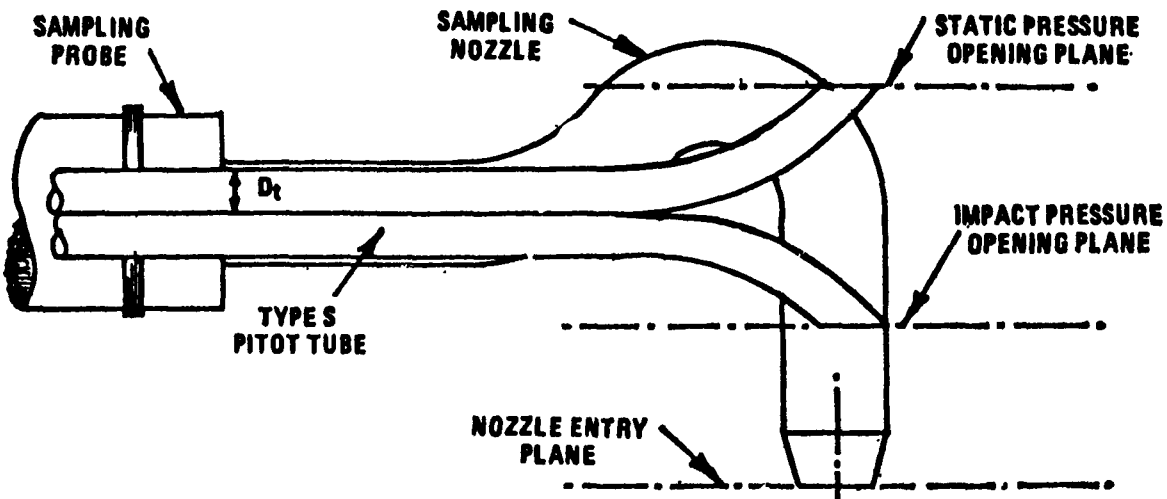
4.1.1 Type S Pitot Tube Assemblies. During sample and velocity traverses, the isolated Type S pitot tube is not always used; in many instances, the pitot tube is used in combination with other source-sampling components (thermocouple, sampling probe, nozzle) as part of an "assembly." The presence of other sampling components can sometimes affect the baseline value of the Type S pitot tube coefficient (Citation 9 in Section 6); therefore an assigned (or otherwise known) baseline coefficient value may or may not be valid for a given assembly. The baseline and assembly coefficient values will be identical only when the relative placement of the components in the assembly is such that aerodynamic interference effects are eliminated. Figures 2-6 through 2-8 illustrate interference-free component arrangements for Type S pitot tubes having external tubing diameters between 0.48 and 0.95 cm (3/16 and 3/8 in.). Type S pitot tube assemblies that fail to meet any or all of the specifications of Figures 2-6 through 2-8 shall be calibrated according to the procedure outlined in Sections 4.1.2 through 4.1.5 below, and prior to calibration, the values of the intercomponent spacings (pitot-nozzle, pitot-thermocouple, pitot-probe sheath) shall be measured and recorded.

NOTE.—Do not use any Type S pitot tube assembly which is constructed such that the impact pressure opening plane of the pitot tube is below the entry plane of the nozzle (see Figure 2-6b).

4.1.2 Calibration Setup. If the Type S pitot tube is to be calibrated, one leg of the tube shall be permanently marked A, and the other, B. Calibration shall be done in a flow system having the following essential design features:[87]



A. BOTTOM VIEW; SHOWING MINIMUM PITOT-NOZZLE SEPARATION.



B. SIDE VIEW; TO PREVENT PITOT TUBE FROM INTERFERING WITH GAS FLOW STREAMLINES APPROACHING THE NOZZLE, THE IMPACT PRESSURE OPENING PLANE OF THE PITOT TUBE SHALL BE EVEN WITH OR ABOVE THE NOZZLE ENTRY PLANE.

Figure 2-6. Proper pitot tube - sampling nozzle configuration to prevent aerodynamic interference; buttonhook - type nozzle; centers of nozzle and pitot opening aligned; D_t between 0.48 and 0.95 cm (3/16 and 3/8 in.).

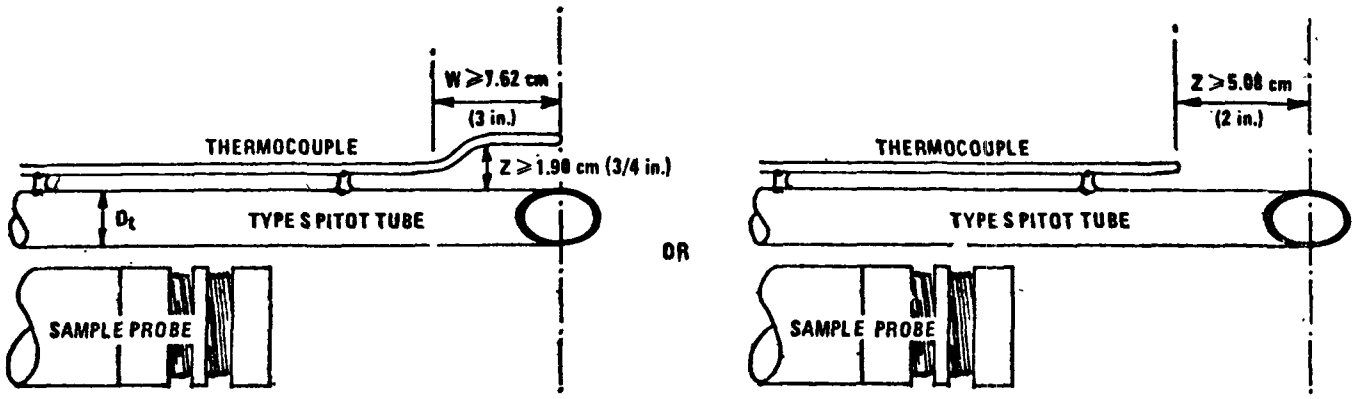


Figure 2-7. Proper thermocouple placement to prevent interference; D_t between 0.48 and 0.95 cm (3/16 and 3/8 in.).

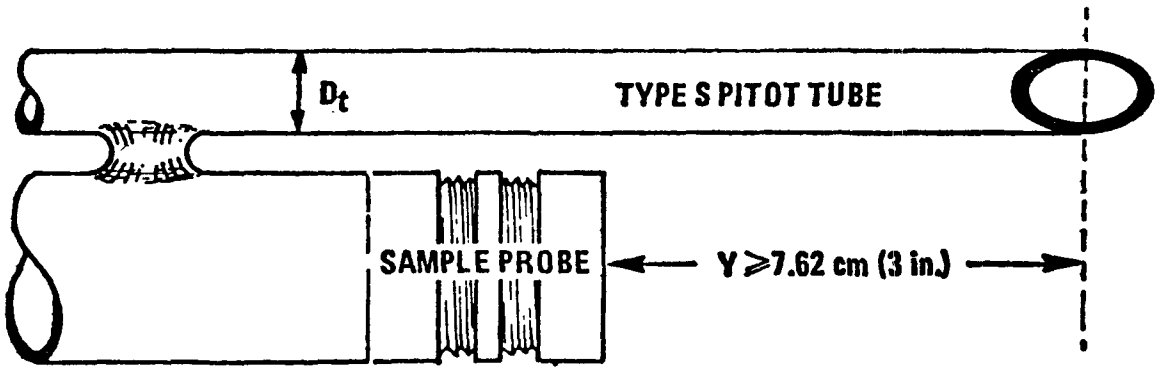


Figure 2-8. Minimum pitot-sample probe separation needed to prevent interference; D_t between 0.48 and 0.95 cm (3/16 and 3/8 in.).

4.1.2.1 The flowing gas stream must be confined to a duct of definite cross-sectional area, either circular or rectangular. For circular cross-sections, the minimum duct diameter shall be 30.5 cm (12 in.); for rectangular cross-sections, the width (shorter side) shall be at least 25.4 cm (10 in.).

4.1.2.2 The cross-sectional area of the calibration duct must be constant over a distance of 10 or more duct diameters. For a rectangular cross-section, use an equivalent diameter, calculated from the following equation, to determine the number of duct diameters:

$$D_e = \frac{2LW}{(L+W)}$$

Equation 2-1

where:
D_e = Equivalent diameter
L = Length
W = Width

To ensure the presence of stable, fully developed flow patterns at the calibration site, or "test section," the site must be located at least eight diameters downstream and two diameters upstream from the nearest disturbances.

NOTE.—The eight- and two-diameter criteria are not absolute; other test section locations may be used (subject to approval of the Administrator), provided that the flow at the test site is stable and demonstrably parallel to the duct axis.

4.1.2.3 The flow system shall have the capacity to generate a test-section velocity around 915 m/min (3,000 ft/min). This velocity must be constant with time to guarantee steady flow during calibration. Note that Type S pitot tube coefficients obtained by single-velocity calibration at 915 m/min (3,000 ft/min) will generally be valid to within ±3 percent for the measurement of velocities above 305 m/min (1,000 ft/min) and to within ±5 to 6 percent for the measurement of velocities between 180 and 305 m/min (600 and 1,000 ft/min). If a more precise correlation between C_p and velocity is desired, the flow system shall have the capacity to generate at least four distinct, time-invariant test-section velocities covering the velocity range from 180 to 1,525 m/min (600 to 5,000 ft/min), and calibration data shall be taken at regular velocity intervals over this range (see Citations 9 and 14 in Section 6 for details).

4.1.2.4 Two entry ports, one each for the standard and Type S pitot tubes, shall be cut in the test section; the standard pitot entry port shall be located slightly downstream of the Type S port, so that the standard and Type S impact openings will lie in the same cross-sectional plane during calibration. To facilitate alignment of the pitot tubes during calibration, it is advisable that the test section be constructed of plexiglas or some other transparent material.

4.1.3 Calibration Procedure. Note that this procedure is a general one and must not be used without first referring to the special considerations presented in Section 4.1.5. Note also that this procedure applies only to single-velocity calibration. To obtain calibration data for the A and B sides of the Type S pitot tube, proceed as follows:

4.1.3.1 Make sure that the manometer is properly filled and that the oil is free from contamination and is of the proper density. Inspect and leak-check all pitot lines; repair or replace if necessary.

4.1.3.2 Level and zero the manometer. Turn on the fan and allow the flow to stabilize. Seal the Type S entry port.

4.1.3.3 Ensure that the manometer is level and zeroed. Position the standard pitot tube at the calibration point (determined as outlined in Section 4.1.5.1), and align the tube so that its tip is pointed directly into the flow. Particular care should be taken in aligning the tube to avoid yaw and pitch angles. Make sure that the entry port surrounding the tube is properly sealed.

4.1.3.4 Read Δp_{std} and record its value in a data table similar to the one shown in Figure 2-9. Remove the standard pitot tube from the duct and disconnect it from the manometer. Seal the standard entry port.

4.1.3.5 Connect the Type S pitot tube to the manometer. Open the Type S entry port. Check the manometer level and zero. Insert and align the Type S pitot tube so that its A side impact opening is at the same point as was the standard pitot tube and is pointed directly into the flow. Make sure that the entry port surrounding the tube is properly sealed.

4.1.3.6 Read Δp_a and enter its value in the data table. Remove the Type S pitot tube from the duct and disconnect it from the manometer.

4.1.3.7 Repeat steps 4.1.3.3 through 4.1.3.6 above until three pairs of Δp readings have been obtained.

4.1.3.8 Repeat steps 4.1.3.3 through 4.1.3.7 above for the B side of the Type S pitot tube.

4.1.3.9 Perform calculations, as described in Section 4.1.4 below.

4.1.4 Calculations.

4.1.4.1 For each of the six pairs of Δp readings (i.e., three from side A and three from side B) obtained in Section 4.1.3 above, calculate the value of the Type S pitot tube coefficient as follows:

PITOT TUBE IDENTIFICATION NUMBER: _____ DATE: _____

CALIBRATED BY: _____

"A" SIDE CALIBRATION				
RUN NO.	Δp_{std} cm H_2O (in. H_2O)	$\Delta p_{(s)}$ cm H_2O (in. H_2O)	$C_{p(s)}$	DEVIATION $C_{p(s)} - \bar{C}_p$(A)
1				
2				
3				
		$\bar{C}_p$ (SIDE A)		

"B" SIDE CALIBRATION				
RUN NO.	Δp_{std} cm H_2O (in. H_2O)	$\Delta p_{(s)}$ cm H_2O (in. H_2O)	$C_{p(s)}$	DEVIATION $C_{p(s)} - \bar{C}_p$(B)
1				
2				
3				
		$\bar{C}_p$ (SIDE B)		

$$\text{AVERAGE DEVIATION} = \sigma\text{(A OR B)} = \frac{\sum_1^3 \left| C_{p(s)} - \bar{C}_p(\text{A OR B}) \right|}{3} \leftarrow \text{MUST BE} \leqslant 0.01$$

$$\left| \bar{C}_p \text{ (SIDE A)} - \bar{C}_p \text{ (SIDE B)} \right| \leftarrow \text{MUST BE} \leqslant 0.01$$

Figure 2-9. Pitot tube calibration data.

$$C_{p(s)} = C_{p(std)} \sqrt{\frac{\Delta p_{std}}{\Delta p_s}}$$

Equation 2-2

where:

$C_{p(s)}$ = Type S pitot tube coefficient [87]

$C_{p(std)}$ = Standard pitot tube coefficient; use 0.99 if the coefficient is unknown and the tube is designed according to the criteria of Sections 2.7.1 to 2.7.5 of this method.

Δp_{std} = Velocity head measured by the standard pitot tube, cm H_2O (in. H_2O)

Δp_s = Velocity head measured by the Type S pitot tube, cm H_2O (in. H_2O)

4.1.4.2 Calculate $\bar{C}_p$ (side A), the mean A-side coefficient, and $\bar{C}_p$ (side B), the mean B-side coefficient; calculate the difference between these two average values.

4.1.4.3 Calculate the deviation of each of the three A-side values of $C_{p(s)}$ from $\bar{C}_p$ (side A), and the deviation of each B-side value of $C_{p(s)}$ from $\bar{C}_p$ (side B). Use the following equation:

$$\text{Deviation} = C_{p(s)} - \bar{C}_p(\text{A or B})$$

Equation 2-3

4.1.4.4 Calculate σ, the average deviation from the mean, for both the A and B sides of the pitot tube. Use the following equation:

$$\sigma \text{ (side A or B)} = \frac{\sum_1^3 |C_{p(s)} - \bar{C}_p(A \text{ or } B)|}{3}$$

Equation 2-4

4.1.4.5 Use the Type S pitot tube only if the values of σ (side A) and σ (side B) are less than or equal to 0.01 and if the absolute value of the difference between $\bar{C}_p$ (A) and $\bar{C}_p$ (B) is 0.01 or less.

4.1.5 Special considerations.

4.1.5.1 Selection of calibration point.

4.1.5.1.1 When an isolated Type S pitot tube is calibrated, select a calibration point at or near the center of the duct, and follow the procedures outlined in Sections 4.1.3 and 4.1.4 above. The Type S pitot coefficients so obtained, i.e., $\bar{C}_p$ (side A) and $\bar{C}_p$ (side B), will be valid, so long as either: (1) the isolated pitot tube is used; or (2) the pitot tube is used with other components (nozzle, thermocouple, sample probe) in an arrangement that is free from aerodynamic interference effects (see Figures 2-6 through 2-8).

4.1.5.1.2 For Type S pitot tube-thermocouple combinations (without sample probe), select a calibration point at or near the center of the duct, and follow the procedures outlined in Sections 4.1.3 and 4.1.4 above: The coefficients so obtained will be valid so long as the pitot tube-thermocouple combination is used by itself or with other components in an interference-free arrangement (Figures 2-6 and 2-8).

4.1.5.1.3 For assemblies with sample probes, the calibration point should be located at or near the center of the duct; however, insertion of a probe sheath into a small duct may cause significant cross-sectional area blockage and yield incorrect coefficient values (Citation 9 in Section 6). Therefore, to minimize the blockage effect, the calibration point may be a few inches off-center if necessary. The actual blockage effect will be negligible when the theoretical blockage, as determined by a projected-area model of the probe sheath, is 2 percent or less of the duct cross-sectional area for assemblies without external sheaths (Figure 2-10a), and 3 percent or less for assemblies with external sheaths (Figure 2-10b).

4.1.5.2 For those probe assemblies in which pitot tube-nozzle interference is a factor (i.e., those in which the pitot-nozzle separation distance fails to meet the specification illustrated in Figure 2-6a), the value of $C_{p(s)}$ depends upon the amount of free-space between the tube and nozzle, and therefore is a function of nozzle size. In these instances, separate calibrations shall be performed with each of the commonly used nozzle sizes in place. Note that the single-velocity calibration technique is acceptable for this purpose, even though the larger nozzle sizes (> 0.635 cm or ¼ in.) are not ordinarily used for isokinetic sampling at velocities around 915 m/min (3,000 ft/min), which is the calibration velocity; note also that it is not necessary to draw an isokinetic sample during calibration (see Citation 19 in Section 6).[87]

4.1.5.3 For a probe assembly constructed such that its pitot tube is always used in the same orientation, only one side of the pitot tube need be calibrated (the side which will face the flow). The pitot tube must still meet the alignment specifications of Figure 2-2 or 2-3, however, and must have an average deviation (σ) value of 0.01 or less (see Section 4.1.4.4).

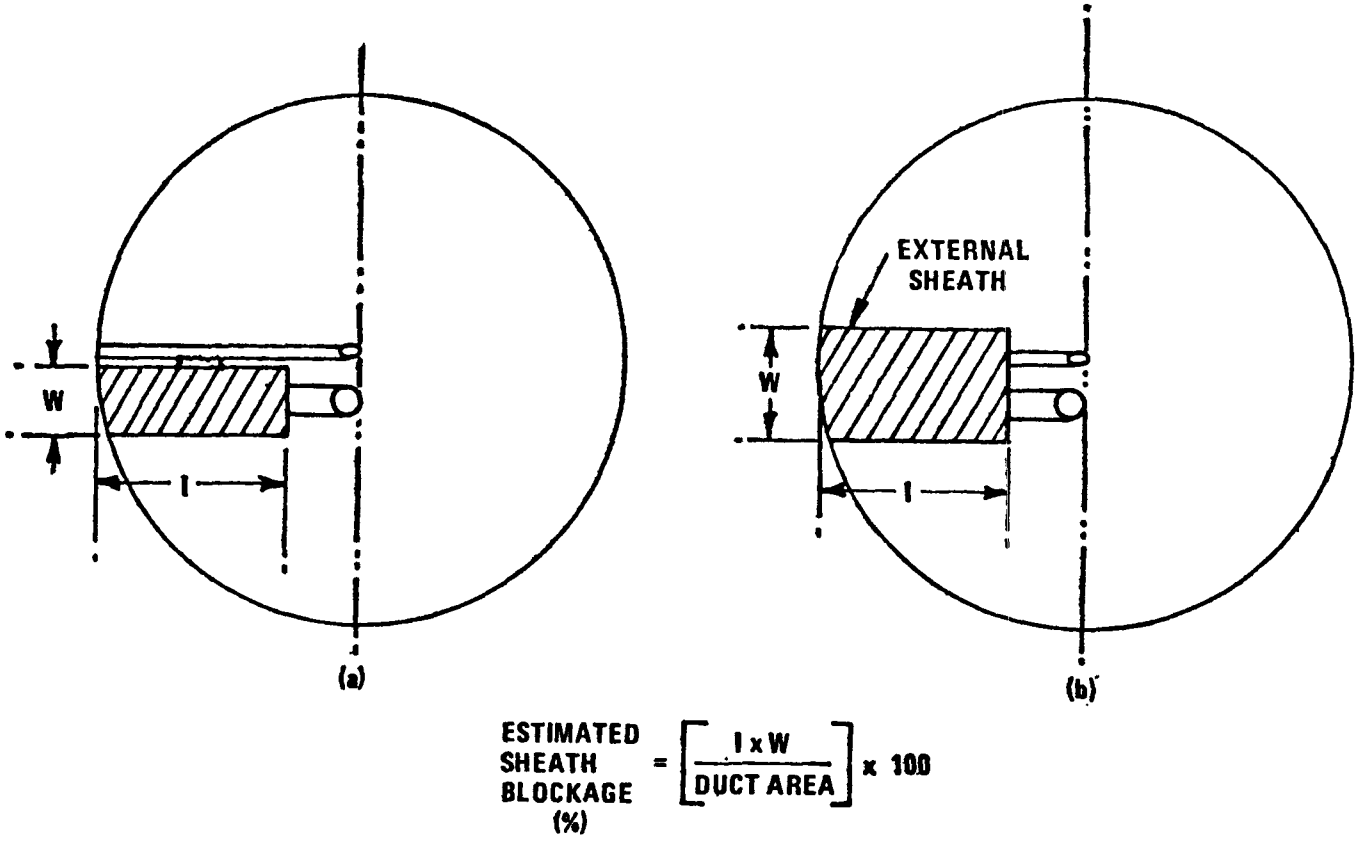


Figure 2-10. Projected-area models for typical pitot tube assemblies.

4.1.6 Field Use and Recalibration.

4.1.6.1 Field Use.

4.1.6.1.1 When a Type S pitot tube (isolated tube or assembly) is used in the field, the appropriate coefficient value (whether assigned or obtained by calibration) shall be used to perform velocity calculations. For calibrated Type S pitot tubes, the A side coefficient shall be used when the A side of the tube faces the flow, and the B side coefficient shall be used when the B side faces the flow; alternatively, the arithmetic average of the A and B side coefficient values may be used, irrespective of which side faces the flow.

4.1.6.1.2 When a probe assembly is used to sample a small duct (12 to 36 in. in diameter), the probe sheath sometimes blocks a significant part of the duct cross-section, causing a reduction in the effective value of $\overline{C}_{p(s)}$. Consult Citation 9 in Section 6 for details. Conventional pitot-sampling probe assemblies are not recommended for use in ducts having inside diameters smaller than 12 inches (Citation 16 in Section 6).

4.1.6.2 Recalibration.

4.1.6.2.1 Isolated Pitot Tubes. After each field use, the pitot tube shall be carefully reexamined in top, side, and end views. If the pitot face openings are still aligned within the specifications illustrated in Figure 2-2 or 2-3, it can be assumed that the baseline coefficient of the pitot tube has not changed. If, however, the tube has been damaged to the extent that it no longer meets the specifications of Figure 2-2 or 2-3, the damage shall either be repaired to restore proper alignment of the face openings or the tube shall be discarded.

4.1.6.2.2 Pitot Tube Assemblies. After each field use, check the face opening alignment of the pitot tube, as in Section 4.1.6.2.1; also, remeasure the intercomponent spacings of the assembly. If the intercomponent spacings have not changed and the face opening alignment is acceptable, it can be assumed that the coefficient of the assembly has not changed. If the face opening alignment is no longer within the specifications of Figures 2-2 or 2-3, either repair the damage or replace the pitot tube (calibrating the new assembly, if necessary). If the intercomponent spacings have changed, restore the original spacings or recalibrate the assembly.

4.2 Standard pitot tube (if applicable). If a standard pitot tube is used for the velocity traverse, the tube shall be constructed according to the criteria of Section 2.7 and shall be assigned a baseline coefficient value of 0.99. If the standard pitot tube is used as part of an assembly, the tube shall be in an interference-free arrangement (subject to the approval of the Administrator).

4.3 Temperature Gauges. After each field use, calibrate dial thermometers, liquid-filled bulb thermometers, thermocouple-potentiometer systems, and other gauges at a temperature within 10 percent of the average absolute stack temperature. For temperatures up to 405° C (761° F), use an ASTM mercury-in-glass reference thermometer, or equivalent, as a reference; alternatively, either a reference thermocouple and potentiometer (calibrated by NBS) or thermometric fixed points, e.g., ice bath and boiling water (corrected for barometric pressure) may be used. For temperatures above 405° C (761° F), use an NBS-calibrated reference thermocouple-potentiometer system or an alternate reference, subject to the approval of the Administrator.

If, during calibration, the absolute temperatures measured with the gauge being calibrated and the reference gauge agree within 1.5 percent, the temperature data taken in the field shall be considered valid. Otherwise, the pollutant emission test shall either be considered invalid or adjustments (if appropriate) of the test results shall be made, subject to the approval of the Administrator.

4.4 Barometer. Calibrate the barometer used against a mercury barometer.

5. *Calculations*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

5.1 Nomenclature.

A = Cross-sectional area of stack, m^2 (ft^2).

B_{ws} = Water vapor in the gas stream (from Method 5 or Reference Method 4), proportion by volume.

C_p = Pitot tube coefficient, dimensionless.

K_p = Pitot tube constant,

$$34.97 \frac{\text{m}}{\text{sec}} \left[\frac{(g/g\text{-mole})(\text{mm Hg})}{(°\text{K})(\text{mm } H_2O)}\right]^{1/2}$$

for the metric system and

$$85.49 \frac{\text{ft}}{\text{sec}} \left[\frac{(\text{lb/lb-mole})(\text{in. Hg})}{(°\text{R})(\text{in. } H_2O)}\right]^{1/2}$$

for the English system.

M_d = Molecular weight of stack gas, dry basis (see Section 3.6) g/g-mole (lb/lb-mole).

M_s = Molecular weight of stack gas, wet basis, g/g-mole (lb/lb-mole).

$$= M_d(1-B_{ws}) + 18.0\,B_{ws} \qquad \text{Equation 2-5}$$

P_{bar} = Barometric pressure at measurement site, mm Hg (in. Hg).

P_g = Stack static pressure, mm Hg (in. Hg).

P_s = Absolute stack gas pressure, mm Hg (in. Hg).

$$= P_{bar} + P_g \qquad \text{Equation 2-6}$$

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

Q_{sd} = Dry volumetric stack gas flow rate corrected to standard conditions, dscm/hr (dscf/hr).

t_s = Stack temperature, °C (°F).

T_s = Absolute stack temperature, °K (°R).

$$= 273 + t_s \text{ for metric} \qquad \text{Equation 2-7}$$

$$= 460 + t_s \text{ for English} \qquad \text{Equation 2-8}$$

T_{std} = Standard absolute temperature, 293 °K (528° R)

v_s = Average stack gas velocity, m/sec (ft/sec).

Δp = Velocity head of stack gas, mm H_2O (in. H_2O).

3,600 = Conversion factor, sec/hr.

18.0 = Molecular weight of water, g/g-mole (lb-lb-mole).

5.2 Average stack gas velocity.

$$v_s = K_p C_p (\sqrt{\Delta p})_{avg} \sqrt{\frac{T_{s(avg)}}{P_s M_s}}$$

Equation 2-9

5.3 Average stack gas dry volumetric flow rate,

$$Q_{sd} = 3{,}600(1-B_{ws})v_s A \left(\frac{T_{std}}{T_{s(avg)}}\right)\left(\frac{P_s}{P_{std}}\right)$$

Equation 2-10

6. *Bibliography*

1. Mark, L. S. Mechanical Engineers' Handbook. New York, McGraw-Hill Book Co., Inc. 1951.

2. Perry, J. H. Chemical Engineers' Handbook. New York. McGraw-Hill Book Co., Inc. 1960.

3 Shigehara, R. T., W. F. Todd, and W. S. Smith. Significance of Errors in Stack Sampling Measurements. U.S. Environmental Protection Agency, Research Triangle Park, N.C. (Presented at the Annual Meeting of the Air Pollution Control Association, St. Louis, Mo., June 14-19, 1970.)

4. Standard Method for Sampling Stacks for Particulate Matter. In: 1971 Book of ASTM Standards, Part 23. Philadelphia, Pa. 1971. ASTM *Designation* D-2928-71.

5 Vennard, J. K. Elementary Fluid Mechanics. New York John Wiley and Sons, Inc. 1947.

6. Fluid Meters—Their Theory and Application. American Society of Mechanical Engineers, New York, N.Y. 1959.

7. ASHRAE Handbook of Fundamentals. 1972. p. 208.

8 Annual Book of ASTM Standards, Part 26. 1974. p. 648.

9. Vollaro, R. F. Guidelines for Type S Pitot Tube Calibration. U.S. Environmental Protection Agency, Research Triangle Park, N.C. (Presented at 1st Annual Meeting, Source Evaluation Society, Dayton, Ohio, September 18, 1975.)87

10. Vollaro, R. F. A Type S Pitot Tube Calibration Study. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, N.C. July 1974.

11. Vollaro, R. F. The Effects of Impact Opening Misalignment on the Value of the Type S Pitot Tube Coefficient. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, N.C. October 1976.

12. Vollaro, R. F. Establishment of a Baseline Coefficient Value for Properly Constructed Type S Pitot Tubes. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, N.C. November 1976.

13. Vollaro, R. F. An Evaluation of Single-Velocity Calibration Technique as a Means of Determining Type S Pitot Tube Coefficients. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, N.C. August 1975.87

14 Vollaro, R. F. The Use of Type S Pitot Tubes for the Measurement of Low Velocities. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, N.C. November 1976.

15. Smith, Marvin L. Velocity Calibration of EPA Type Source Sampling Probe. United Technologies Corporation, Pratt and Whitney Aircraft Division, East Hartford, Conn. 1975.

16. Vollaro, R. F. Recommended Procedure for Sample Traverses in Ducts Smaller than 12 Inches in Diameter. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, N.C. November 1976.

17. Ower, E. and R. C. Pankhurst. The Measurement of Air Flow, 4th Ed., London, Pergamon Press. 1966.

18. Vollaro, R. F. A Survey of Commercially Available Instrumentation for the Measurement of Low-Range Gas Velocities. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, N.C. November 1976. (Unpublished Paper) 87

19. Gnyp, A. W., C. C. St. Pierre, D. S. Smith, D. Mozzon, and J. Steiner. An Experimental Investigation of the Effect of Pitot Tube-Sampling Probe Configurations on the Magnitude of the S Type Pitot Tube Coefficient for Commercially Available Source Sampling Probes. Prepared by the University of Windsor for the Ministry of the Environment, Toronto, Canada. February 1975.

METHOD 3—GAS ANALYSIS FOR CARBON DIOXIDE, OXYGEN, EXCESS AIR, AND DRY MOLECULAR WEIGHT

1. *Principle and Applicability*

1.1 Principle. A gas sample is extracted from a stack, by one of the following methods: (1) single-point, grab sampling; (2) single-point, integrated sampling; or (3) multi-point, integrated sampling. The gas sample is analyzed for percent carbon dioxide (CO_2), percent oxygen (O_2), and, if necessary, percent carbon monoxide (CO). If a dry molecular weight determination is to be made, either an Orsat or a Fyrite [1] analyzer may be used for the analysis; for excess air or emission rate correction factor determination, an Orsat analyzer must be used.

1.2 Applicability. This method is applicable for determining CO_2 and O_2 concentrations, excess air, and dry molecular weight of a sample from a gas stream of a fossil-fuel combustion process. The method may also be applicable to other processes where it has been determined that compounds other than CO_2, O_2, CO, and nitrogen (N_2) are not present in concentrations sufficient to affect the results.

Other methods, as well as modifications to the procedure described herein, are also applicable for some or all of the above determinations. Examples of specific methods and modifications include: (1) a multi-point sampling method using an Orsat analyzer to analyze individual grab samples obtained at each point; (2) a method using CO_2 or O_2 and stoichiometric calculations to determine dry molecular weight and excess air; (3) assigning a value of 30.0 for dry molecular weight, in lieu of actual measurements, for processes burning natural gas, coal, or oil. These methods and modifications may be used, but are subject to the approval of the Administrator, U S Environmental Protection Agency. 87

2. *Apparatus*

As an alternative to the sampling apparatus and systems described herein, other sampling systems (e g., liquid displacement) may be used provided such systems are capable of obtaining a representative sample and maintaining a constant sampling rate, and are otherwise capable of yielding acceptable results. Use of such systems is subject to the approval of the Administrator.

2.1 Grab Sampling (Figure 3-1).

2.1.1 Probe. The probe should be made of stainless steel or borosilicate glass tubing and should be equipped with an in-stack or out-stack filter to remove particulate matter (a plug of glass wool is satisfactory for this purpose). Any other material inert to O_2, CO_2, CO, and N_2 and resistant to temperature at sampling conditions may be used for the probe; examples of such material are aluminum, copper, quartz glass and Teflon.

2.1.2 Pump. A one-way squeeze bulb, or equivalent, is used to transport the gas sample to the analyzer.

2.2 Integrated Sampling (Figure 3-2).

2.2.1 Probe. A probe such as that described in Section 2.1.1 is suitable.

2.2.2 Condenser. An air-cooled or water-cooled condenser, or other condenser that will not remove O_2, CO_2, CO, and N_2, may be used to remove excess moisture which would interfere with the operation of the pump and flow meter.

2.2.3 Valve. A needle valve is used to adjust sample gas flow rate.

2.2.4 Pump. A leak-free, diaphragm-type pump, or equivalent, is used to transport sample gas to the flexible bag. Install a small surge tank between the pump and rate meter to eliminate the pulsation effect of the diaphragm pump on the rotameter.

2.2.5 Rate Meter. The rotameter, or equivalent rate meter, used should be capable of measuring flow rate to within ±2 percent of the selected flow rate. A flow rate range of 500 to 1000 cm^3/min is suggested.

2.2.6 Flexible Bag. Any leak-free plastic (e g , Tedlar, Mylar, Teflon) or plastic-coated aluminum (e g , aluminized Mylar) bag, or equivalent, having a capacity consistent with the selected flow rate and time length of the test run, may be used. A capacity in the range of 55 to 90 liters is suggested.

To leak-check the bag, connect it to a water manometer and pressurize the bag to 5 to 10 cm H_2O (2 to 4 in. H_2O). Allow to stand for 10 minutes. Any displacement in the water manometer indicates a leak. An alternative leak-check method is to pressurize the bag to 5 to 10 cm H_2O (2 to 4 in. H_2O) and allow to stand overnight. A deflated bag indicates a leak.

2.2.7 Pressure Gauge. A water-filled U-tube manometer, or equivalent, of about 28 cm (12 in.) is used for the flexible bag leak-check.

2.2.8 Vacuum Gauge. A mercury manometer, or equivalent, of at least 760 mm Hg (30 in. Hg) is used for the sampling train leak-check.

2.3 Analysis. For Orsat and Fyrite analyzer maintenance and operation procedures, follow the instructions recommended by the manufacturer, unless otherwise specified herein.

2.3.1 Dry Molecular Weight Determination. An Orsat analyzer or Fyrite type combustion gas analyzer may be used.

2.3.2 Emission Rate Correction Factor or Excess Air Determination. An Orsat analyzer must be used. For low CO_2 (less than 4.0 percent) or high O_2 (greater than 15.0 percent) concentrations, the measuring burette of the Orsat must have at least 0.1 percent subdivisions.

3. *Dry Molecular Weight Determination*

Any of the three sampling and analytical procedures described below may be used for determining the dry molecular weight.

3.1 Single-Point, Grab Sampling and Analytical Procedure.

3.1.1 The sampling point in the duct shall either be at the centroid of the cross section or at a point no closer to the walls than 1.00 m (3.3 ft), unless otherwise specified by the Administrator.

3.1.2 Set up the equipment as shown in Figure 3-1, making sure all connections ahead of the analyzer are tight and leak-free. If an Orsat analyzer is used, it is recommended that the analyzer be leaked-checked by following the procedure in Section 5; however, the leak-check is optional.

3.1.3 Place the probe in the stack, with the tip of the probe positioned at the sampling point; purge the sampling line. Draw a sample into the analyzer and immediately analyze it for percent CO_2 and percent O_2. Determine the percentage of the gas that is N_2 and CO by subtracting the sum of the percent CO_2 and percent O_2 from 100 percent. Calculate the dry molecular weight as indicated in Section 6.3.

3.1.4 Repeat the sampling, analysis, and calculation procedures, until the dry molecular weights of any three grab samples differ from their mean by no more than 0.3 g/g-mole (0.3 lb/lb-mole). Average these three molecular weights, and report the results to the nearest 0.1 g/g-mole (lb/lb-mole).

3.2 Single-Point, Integrated Sampling and Analytical Procedure.

3.2.1 The sampling point in the duct shall be located as specified in Section 3.1.1.

3.2.2 Leak-check (optional) the flexible bag as in Section 2.2.6. Set up the equipment as shown in Figure 3-2. Just prior to sampling, leak-check (optional) the train by placing a vacuum gauge at the condenser inlet, pulling a vacuum of at least 250 mm Hg (10 in. Hg), plugging the outlet at the quick disconnect, and then turning off the pump. The vacuum should remain stable for at least 0.5 minute. Evacuate the flexible bag. Connect the probe and place it in the stack, with the tip of the probe positioned at the sampling point; purge the sampling line. Next, connect the bag and make sure that all connections are tight and leak free.

3.2.3 Sample at a constant rate. The sampling run should be simultaneous with, and for the same total length of time as, the pollutant emission rate determination. Collection of at least 30 liters (1.00 ft^3) of sample gas is recommended; however, smaller volumes may be collected, if desired.

3.2.4 Obtain one integrated flue gas sample during each pollutant emission rate determination. Within 8 hours after the sample is taken, analyze it for percent CO_2 and percent O_2 using either an Orsat analyzer or a Fyrite-type combustion gas analyzer. If an Orsat analyzer is used, it is recommended that the Orsat leak-check described in Section 5 be performed before this determination; however, the check is optional. Determine the percentage of the gas that is N_2 and CO by subtracting the sum of the percent CO_2 and percent O_2 from 100 percent. Calculate the dry molecular weight as indicated in Section 6.3. 87

[1] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

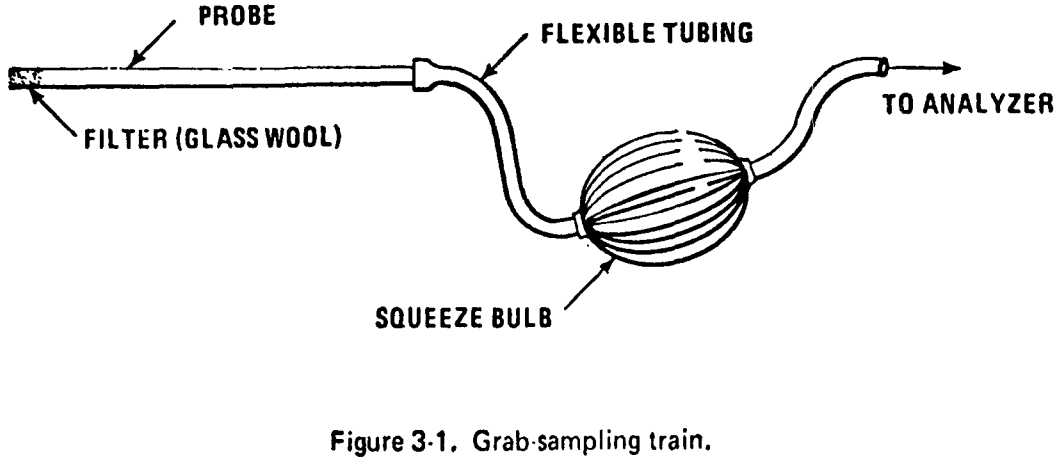


Figure 3-1. Grab-sampling train.

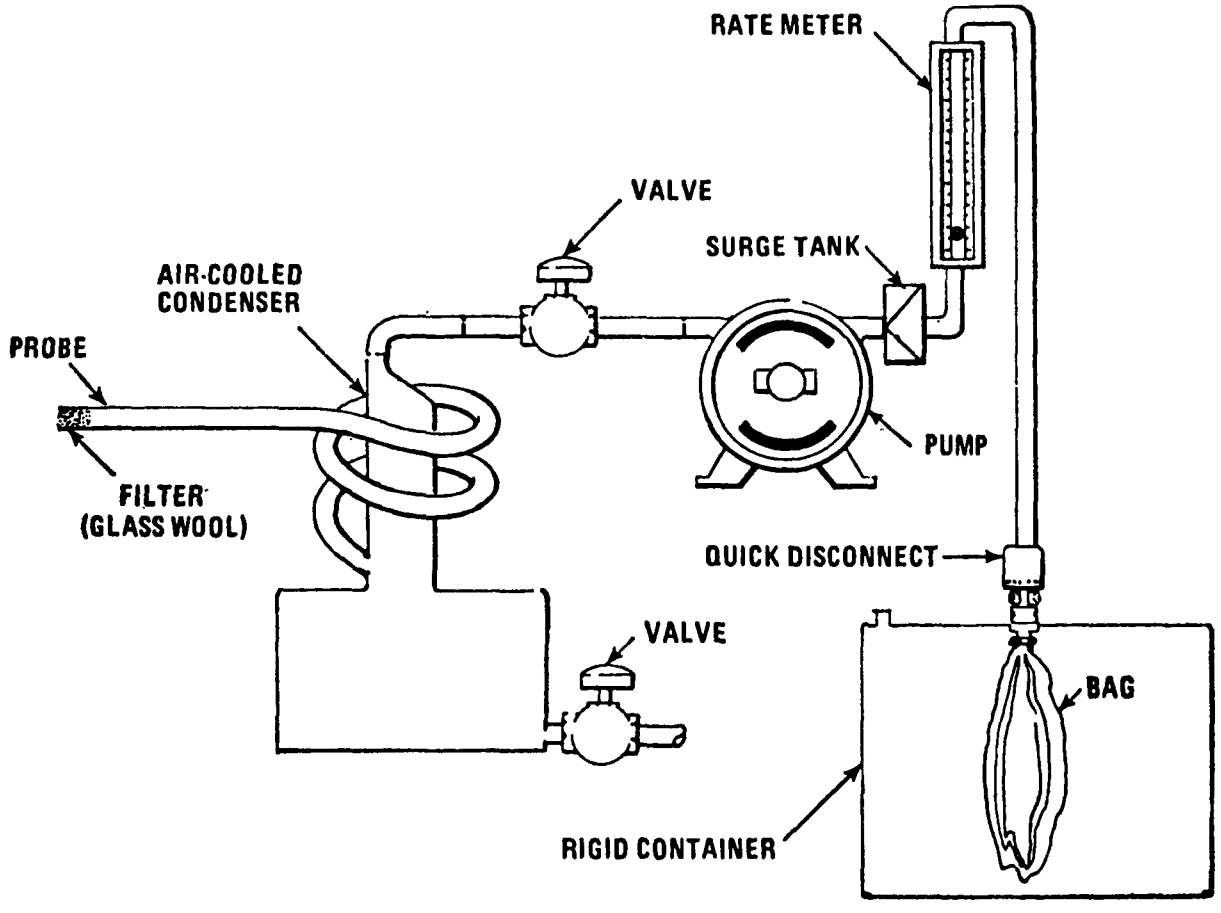


Figure 3-2. Integrated gas-sampling train.

TIME	TRAVERSE PT.	Q 1pm	% DEV.[a]
	AVERAGE		

[a] $\%\ DEV = \left(\frac{Q - Q_{avg}}{Q_{avg}}\right) 100$ (MUST BE $\leq 10\%$)

Figure 3-3. Sampling rate data.

3.3.5 Repeat the analysis and calculation procedures until the individual dry molecular weights for any three analyses differ from their mean by no more than 0.3 g/g-mole (0.3 lb/lb-mole). Average these three molecular weights, and report the results to the nearest 0.1 g/g-mole (0.1 lb/lb-mole).

3.3 Multi-Point, Integrated Sampling and Analytical Procedure.

3.3.1 Unless otherwise specified by the Administrator, a minimum of eight traverse points shall be used for circular stacks having diameters less then 0.61 m (24 in.), a minimum of nine shall be used for rectangular stacks having equivalent diameters less than 0.61 m (24 in.), and a minimum of twelve traverse points shall be used for all other cases. The traverse points shall be located according to Method 1. The use of fewer points is subject to approval of the Administrator.

3.3.2 Follow the procedures outlined in Sections 3.2.2 through 3.2.5, except for the following: traverse all sampling points and sample at each point for an equal length of time. Record sampling data as shown in Figure 3-3.

4. Emission Rate Correction Factor or Excess Air Determination

NOTE.—A Fyrite-type combustion gas analyzer is not acceptable for excess air or emission rate correction factor determination, unless approved by the Administrator. If both percent CO_2 and percent O_2 are measured, the analytical results of any of the three procedures given below may also be used for calculating the dry molecular weight.

Each of the three procedures below shall be used only when specified in an applicable subpart of the standards. The use of these procedures for other purposes must have specific prior approval of the Administrator.

4.1 Single-Point, Grab Sampling and Analytical Procedure.

4.1.1 The sampling point in the duct shall either be at the centroid of the cross-section or at a point no closer to the walls than 1.00 m (3.3 ft), unless otherwise specified by the Administrator.

4.1.2 Set up the equipment as shown in Figure 3-1, making sure all connections ahead of the analyzer are tight and leak-free. Leak-check the Orsat analyzer according to the procedure described in Section 5. This leak-check is mandatory.

4.1.3 Place the probe in the stack, with the tip of the probe positioned at the sampling point; purge the sampling line. Draw a sample into the analyzer. For emission rate correction factor determination, immediately analyze the sample, as outlined in Sections 4.1.4 and 4.1.5, for percent CO_2 or percent O_2. If excess air is desired, proceed as follows: (1) immediately analyze the sample, as in Sections 4.1.4 and 4.1.5, for percent CO_2, O_2, and CO; (2) determine the percentage of the gas that is N_2 by subtracting the sum of the percent CO_2, percent O_2, and percent CO from 100 percent; and (3) calculate percent excess air as outlined in Section 6.2.

4.1.4 To ensure complete absorption of the CO_2, O_2, or if applicable, CO, make repeated passes through each absorbing solution until two consecutive readings are the same. Several passes (three or four) should be made between readings. (If constant readings cannot be obtained after three consecutive readings, replace the absorbing solution.)

4.1.5 After the analysis is completed, leak-check (mandatory) the Orsat analyzer once again, as described in Section 5. For the results of the analysis to be valid, the Orsat analyzer must pass this leak test before and after the analysis. NOTE.—Since this single-point, grab sampling and analytical procedure is normally conducted in conjunction with a single-point, grab sampling and analytical procedure for a pollutant, only one analysis is ordinarily conducted. Therefore, great care must be taken to obtain a valid sample and analysis. Although in most cases only CO_2 or O_2 is required, it is recommended that both CO_2 and O_2 be measured, and that Citation 5 in the Bibliography be used to validate the analytical data.

4.2 Single-Point, Integrated Sampling and Analytical Procedure.

4.2.1 The sampling point in the duct shall be located as specified in Section 4.1.1.

4.2.2 Leak-check (mandatory) the flexible bag as in Section 2.2.6. Set up the equipment as shown in Figure 3-2. Just prior to sampling, leak-check (mandatory) the train by placing a vacuum gauge at the condenser inlet, pulling a vacuum of at least 250 mm Hg (10 in. Hg), plugging the outlet at the quick disconnect, and then turning off the pump. The vacuum shall remain stable for at least 0.5 minute. Evacuate the flexible bag. Connect the probe and place it in the stack, with the tip of the probe positioned at the sampling point; purge the sampling line. Next, connect the bag and make sure that all connections are tight and leak free.

4.2.3 Sample at a constant rate, or as specified by the Administrator. The sampling run must be simultaneous with, and for the same total length of time as, the pollutant emission rate determination. Collect at least 30 liters (1.00 ft^3) of sample gas. Smaller volumes may be collected, subject to approval of the Administrator.

4.2.4 Obtain one integrated flue gas sample during each pollutant emission rate determination. For emission rate correction factor determination, analyze the sample within 4 hours after it is taken for percent CO_2 or percent O_2 (as outlined in Sections 4.2.5 through 4.2.7). The Orsat analyzer must be leak-checked (see Section 5) before the analysis. If excess air is desired, proceed as follows: (1) within 4 hours after the sample is taken, analyze it (as in Sections 4.2.5 through 4.2.7) for percent CO_2, O_2, and CO; (2) determine the percentage of the gas that is N_2 by subtracting the sum of the percent CO_2, percent O_2, and percent CO from 100 percent; (3) calculate percent excess air, as outlined in Section 6.2.

4.2.5 To ensure complete absorption of the CO_2, O_2, or if applicable, CO, make repeated passes through each absorbing solution until two consecutive readings are the same. Several passes (three or four) should be made between readings. (If constant readings cannot be obtained after three consecutive readings, replace the absorbing solution.)

4.2.6 Repeat the analysis until the following criteria are met:

4.2.6.1 For percent CO_2, repeat the analytical procedure until the results of any three analyses differ by no more than (a) 0.3 percent by volume when CO_2 is greater than 4.0 percent or (b) 0.2 percent by volume when CO_2 is less than or equal to 4.0 percent. Average the three acceptable values of percent CO_2 and report the results to the nearest 0.1 percent.

4.2.6.2 For percent O_2, repeat the analytical procedure until the results of any three analyses differ by no more than (a) 0.3 percent by volume when O_2 is less than 15.0 percent or (b) 0.2 percent by volume when O_2 is greater than or equal to 15.0 percent. Average the three acceptable values of percent O_2, and report the results to the nearest 0.1 percent. 87

4.2.6.3 For percent CO, repeat the analytical procedure until the results of any three analyses differ by no more than 0.3 percent. Average the three acceptable values of percent CO and report the results to the nearest 0.1 percent.

4.2.7 After the analysis is completed, leak-check (mandatory) the Orsat analyzer once again, as described in Section 5. For the results of the analysis to be valid, the Orsat analyzer must pass this leak test before and after the analysis. Note: Although in most instances only CO_2 or O_2 is required, it is recommended that both CO_2 and O_2 be measured, and that Citation 5 in the Bibliography be used to validate the analytical data.

4.3 Multi-Point, Integrated Sampling and Analytical Procedure.

4.3.1 Both the minimum number of sampling points and the sampling point location shall be as specified in Section 3.3.1 of this method. The use of fewer points than specified is subject to the approval of the Administrator.

4.3.2 Follow the procedures outlined in Sections 4.2.2 through 4.2.7, except for the following: Traverse all sampling points and sample at each point for an equal length of time. Record sampling data as shown in Figure 3-3.

5. Leak-Check Procedure for Orsat Analyzers

Moving an Orsat analyzer frequently causes it to leak. Therefore, an Orsat analyzer should be thoroughly leak-checked on site before the flue gas sample is introduced into it. The procedure for leak-checking an Orsat analyzer is:

5.1.1 Bring the liquid level in each pipette up to the reference mark on the capillary tubing and then close the pipette stopcock.

5.1.2 Raise the leveling bulb sufficiently to bring the confining liquid meniscus onto the graduated portion of the burette and then close the manifold stopcock.

5.1.3 Record the meniscus position.

5.1.4 Observe the meniscus in the burette and the liquid level in the pipette for movement over the next 4 minutes.

5.1.5 For the Orsat analyzer to pass the leak-check, two conditions must be met.

5.1.5.1 The liquid level in each pipette must not fall below the bottom of the capillary tubing during this 4-minute interval.

5.1.5.2 The meniscus in the burette must not change by more than 0.2 ml during this 4-minute interval.

5.1.6 If the analyzer fails the leak-check procedure, all rubber connections and stopcocks should be checked until the cause of the leak is identified. Leaking stopcocks must be disassembled, cleaned, and regreased. Leaking rubber connections must be replaced. After the analyzer is reassembled, the leak-check procedure must be repeated.

6. Calculations

6.1 Nomenclature.

M_d = Dry molecular weight, g/g-mole (lb/lb-mole).
%EA = Percent excess air.
$\%CO_2$ = Percent CO_2 by volume (dry basis).
$\%O_2$ = Percent O_2 by volume (dry basis).
%CO = Percent CO by volume (dry basis).
$\%N_2$ = Percent N_2 by volume (dry basis).
0.264 = Ratio of O_2 to N_2 in air, v/v.
0.280 = Molecular weight of N_2 or CO, divided by 100.
0.320 = Molecular weight of O_2 divided by 100.
0.440 = Molecular weight of CO_2 divided by 100.

6.2 Percent Excess Air. Calculate the percent excess air (if applicable), by substituting the appropriate values of percent O_2, CO, and N_2 (obtained from Section 4.1.3 or 4.2.4) into Equation 3-1.

$$\%EA = \left[\frac{\%O_2 - 0.5\%CO}{0.264\,\%N_2 - (\%O_2 - 0.5\,\%CO)}\right] 100$$

Equation 3-1 87

NOTE.—The equation above assumes that ambient air is used as the source of O_2 and that the fuel does not contain appreciable amounts of N_2 (as do coke oven or blast furnace gases). For those cases when appreciable amounts of N_2 are present (coal, oil, and natural gas do not contain appreciable amounts of N_2) or when oxygen enrichment is used, alternate methods, subject to approval of the Administrator, are required.

6.3 Dry Molecular Weight. Use Equation 3-2 to calculate the dry molecular weight of the stack gas

$$M_d = 0.440(\%CO_2) + 0.320(\%O_2) + 0.280(\%N_2 + \%CO)$$

Equation 3-2

NOTE.—The above equation does not consider argon in air (about 0.9 percent, molecular weight of 37.7). A negative error of about 0.4 percent is introduced. The tester may opt to include argon in the analysis using procedures subject to approval of the Administrator.

7. Bibliography

1. Altshuller, A. P. Storage of Gases and Vapors in Plastic Bags. International Journal of Air and Water Pollution. *6*:75-81. 1963.

2. Conner, William D. and J. S. Nader. Air Sampling with Plastic Bags. Journal of the American Industrial Hygiene Association. *25*:291-297. 1964. 87

3. Burrell Manual for Gas Analysts, Seventh edition. Burrell Corporation, 2223 Fifth Avenue, Pittsburgh, Pa. 15219. 1951.

4. Mitchell, W. J. and M. R. Midgett. Field Reliability of the Orsat Analyzer. Journal of Air Pollution Control Association *26*:491-495. May 1976.

5. Shigehara, R. T., R. M. Neulicht, and W. S. Smith. Validating Orsat Analysis Data from Fossil Fuel-Fired Units. Stack Sampling News. *4*(2):21-26. August, 1976.

METHOD 4—DETERMINATION OF MOISTURE CONTENT IN STACK GASES

1. *Principle and Applicability*

1.1 Principle. A gas sample is extracted at a constant rate from the source; moisture is removed from the sample stream and determined either volumetrically or gravimetrically.

1.2 Applicability. This method is applicable for determining the moisture content of stack gas.

Two procedures are given. The first is a reference method, for accurate determinations of moisture content (such as are needed to calculate emission data). The second is an approximation method, which provides estimates of percent moisture to aid in setting isokinetic sampling rates prior to a pollutant emission measurement run. The approximation method described herein is only a suggested approach; alternative means for approximating the moisture content, e.g., drying tubes, wet bulb-dry bulb techniques, condensation techniques, stoichiometric calculations, previous experience, etc., are also acceptable.

The reference method is often conducted simultaneously with a pollutant emission measurement run; when it is, calculation of percent isokinetic, pollutant emission rate, etc., for the run shall be based upon the results of the reference method or its equivalent; these calculations shall not be based upon the results of the approximation method, unless the approximation method is shown, to the satisfaction of the Administrator, U.S. Environmental Protection Agency, to be capable of yielding results within 1 percent H_2O of the reference method.

NOTE.—The reference method may yield questionable results when applied to saturated gas streams or to streams that contain water droplets. Therefore, when these conditions exist or are suspected, a second determination of the moisture content shall be made simultaneously with the reference method, as follows: Assume that the gas stream is saturated. Attach a temperature sensor [capable of measuring to ±1° C (2° F)] to the reference method probe. Measure the stack gas temperature at each traverse point (see Section 2.2.1) during the reference method traverse; calculate the average stack gas temperature. Next, determine the moisture percentage, either by: (1) using a psychrometric chart and making appropriate corrections if stack pressure is different from that of the chart, or (2) using saturation vapor pressure tables. In cases where the psychrometric chart or the saturation vapor pressure tables are not applicable (based on evaluation of the process), alternate methods, subject to the approval of the Administrator, shall be used.

2. *Reference Method*

The procedure described in Method 5 for determining moisture content is acceptable as a reference method.

2.1 Apparatus. A schematic of the sampling train used in this reference method is shown in Figure 4-1. All components shall be maintained and calibrated according to the procedure outlined in Method 5.

2.1.1 Probe. The probe is constructed of stainless steel or glass tubing, sufficiently heated to prevent water condensation, and is equipped with a filter, either in-stack (e.g., a plug of glass wool inserted into the end of the probe) or heated out-stack (e.g., as described in Method 5), to remove particulate matter.

When stack conditions permit, other metals or plastic tubing may be used for the probe, subject to the approval of the Administrator.

2.1.2 Condenser. The condenser consists of four impingers connected in series with ground glass, leak-free fittings or any similarly leak-free non-contaminating fittings. The first, third, and fourth impingers shall be of the Greenburg-Smith design, modified by replacing the tip with a 1.3 centimeter (½ inch) ID glass tube extending to about 1.3 cm (½ in.) from the bottom of the flask. The second impinger shall be of the Greenburg-Smith design with the standard tip. Modifications (e.g., using flexible connections between the impingers, using materials other than glass, or using flexible vacuum lines to connect the filter holder to the condenser) may be used, subject to the approval of the Administrator.

The first two impingers shall contain known volumes of water, the third shall be empty, and the fourth shall contain a known weight of 6- to 16-mesh indicating type silica gel, or equivalent desiccant. If the silica gel has been previously used, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. A thermometer, capable of measuring temperature to within 1° C (2° F), shall be placed at the outlet of the fourth impinger, for monitoring purposes.

Alternatively, any system may be used (subject to the approval of the Administrator) that cools the sample gas stream and allows measurement of both the water that has been condensed and the moisture leaving the condenser, each to within 1 ml or 1 g. Acceptable means are to measure the condensed water, either gravimetrically or volumetrically, and to measure the moisture leaving the condenser by: (1) monitoring the temperature and pressure at the exit of the condenser and using Dalton's law of partial pressures, or (2) passing the sample gas stream through a tared silica gel (or equivalent desiccant) trap, with exit gases kept below 20° C (68° F), and determining the weight gain. 87

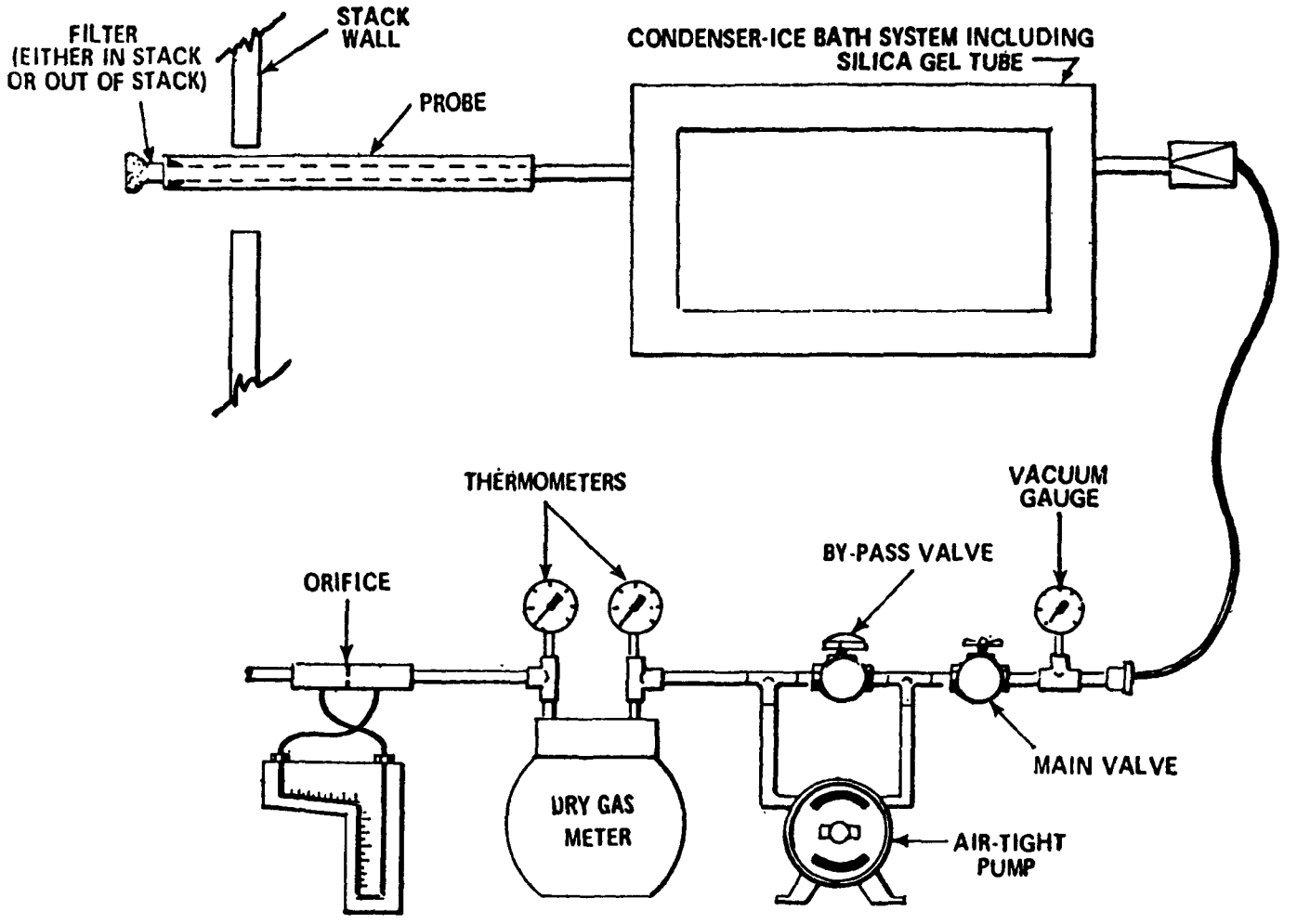


Figure 4-1. Moisture sampling train-reference method.

If means other than silica gel are used to determine the amount of moisture leaving the condenser, it is recommended that silica gel (or equivalent) still be used between the condenser system and pump, to prevent moisture condensation in the pump and metering devices and to avoid the need to make corrections for moisture in the metered volume.

2.1.3 Cooling System. An ice bath container and crushed ice (or equivalent) are used to aid in condensing moisture.

2.1.4 Metering System. This system includes a vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3° C (5.4° F), dry gas meter capable of measuring volume to within 2 percent, and related equipment as shown in Figure 4-1. Other metering systems, capable of maintaining a constant sampling rate and determining sample gas volume, may be used, subject to the approval of the Administrator.

2.1.5 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg) may be used. In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and the sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.

2.1.6 Graduated Cylinder and/or Balance. These items are used to measure condensed water and moisture caught in the silica gel to within 1 ml or 0.5 g. Graduated cylinders shall have subdivisions no greater than 2 ml. Most laboratory balances are capable of weighing to the nearest 0.5 g or less. These balances are suitable for use here.

2.2 Procedure. The following procedure is written for a condenser system (such as the impinger system described in Section 2.1.2) incorporating volumetric analysis to measure the condensed moisture, and silica gel and gravimetric analysis to measure the moisture leaving the condenser.

2.2.1 Unless otherwise specified by the Administrator, a minimum of eight traverse points shall be used for circular stacks having diameters less than 0.61 m (24 in.), a minimum of nine points shall be used for rectangular stacks having equivalent diameters less than 0.61 m (24 in.), and a minimum of twelve traverse points shall be used in all other cases. The traverse points shall be located according to Method 1. The use of fewer points is subject to the approval of the Administrator. Select a suitable probe and probe length such that all traverse points can be sampled. Consider sampling from opposite sides of the stack (four total sampling ports) for large stacks, to permit use of shorter probe lengths. Mark the probe with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point. Place known volumes of water in the first two impingers. Weigh and record the weight of the silica gel to the nearest 0.5 g, and transfer the silica gel to the fourth impinger; alternatively, the silica gel may first be transferred to the impinger, and the weight of the silica gel plus impinger recorded.[87]

2.2.2 Select a total sampling time such that a minimum total gas volume of 0.60 scm (21 scf) will be collected, at a rate no greater than 0.021 m³/min (0.75 cfm). When both moisture content and pollutant emission rate are to be determined, the moisture determination shall be simultaneous with, and for the same total length of time as, the pollutant emission rate run, unless otherwise specified in an applicable subpart of the standards.

2.2.3 Set up the sampling train as shown in Figure 4-1. Turn on the probe heater and (if applicable) the filter heating system to temperatures of about 120° C (248° F), to prevent water condensation ahead of the condenser; allow time for the temperatures to stabilize. Place crushed ice in the ice bath container. It is recommended, but not required, that a leak check be done, as follows: Disconnect the probe from the first impinger or (if applicable) from the filter holder. Plug the inlet to the first impinger (or filter holder) and pull a 380 mm (15 in.) Hg vacuum; a lower vacuum may be used, provided that it is not exceeded during the test. A leakage rate in excess of 4 percent of the average sampling rate or 0.00057 m³/min (0.02 cfm), whichever is less, is unacceptable. Following the leak check, reconnect the probe to the sampling train.[87]

2.2.4 During the sampling run, maintain a sampling rate within 10 percent of constant rate, or as specified by the Administrator. For each run, record the data required on the example data sheet shown in Figure 4-2. Be sure to record the dry gas meter reading at the beginning and end of each sampling time increment and whenever sampling is halted. Take other appropriate readings at each sample point, at least once during each time increment.

2.2.5 To begin sampling, position the probe tip at the first traverse point. Immediately start the pump and adjust the flow to the desired rate. Traverse the cross section, sampling at each traverse point for an equal length of time. Add more ice and, if necessary, salt to maintain a temperature of less than 20° C (68° F) at the silica gel outlet.

2.2.6 After collecting the sample, disconnect the probe from the filter holder (or from the first impinger) and conduct a leak check (mandatory) as described in Section 2.2.3. Record the leak rate. If the leakage rate exceeds the allowable rate, the tester shall either reject the test results or shall correct the sample volume as in Section 6.3 of Method 5. Next, measure the volume of the moisture condensed to the nearest ml. Determine the increase in weight of the silica gel (or silica gel plus impinger) to the nearest 0.5 g. Record this information (see example data sheet, Figure 4-3) and calculate the moisture percentage, as described in 2.3 below.

PLANT_____

LOCATION_____

OPERATOR_____

DATE_____

RUN NO._____

AMBIENT TEMPERATURE_____

BAROMETRIC PRESSURE_____

PROBE LENGTH m(ft)_____

SCHEMATIC OF STACK CROSS SECTION

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	STACK TEMPERATURE °C (°F)	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER (ΔH), mm(in.) H_2O	METER READING GAS SAMPLE VOLUME m^3 (ft^3)	ΔV_m m^3 (ft^3)	GAS SAMPLE TEMPERATURE AT DRY GAS METER		TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °C (°F)
						INLET ($T_{m_{in}}$), °C (°F)	OUTLET ($T_{m_{out}}$), °C (°F)	
TOTAL						Avg.	Avg.	
AVERAGE						Avg.		

Figure 4-2. Field moisture determination-reference method.[87]

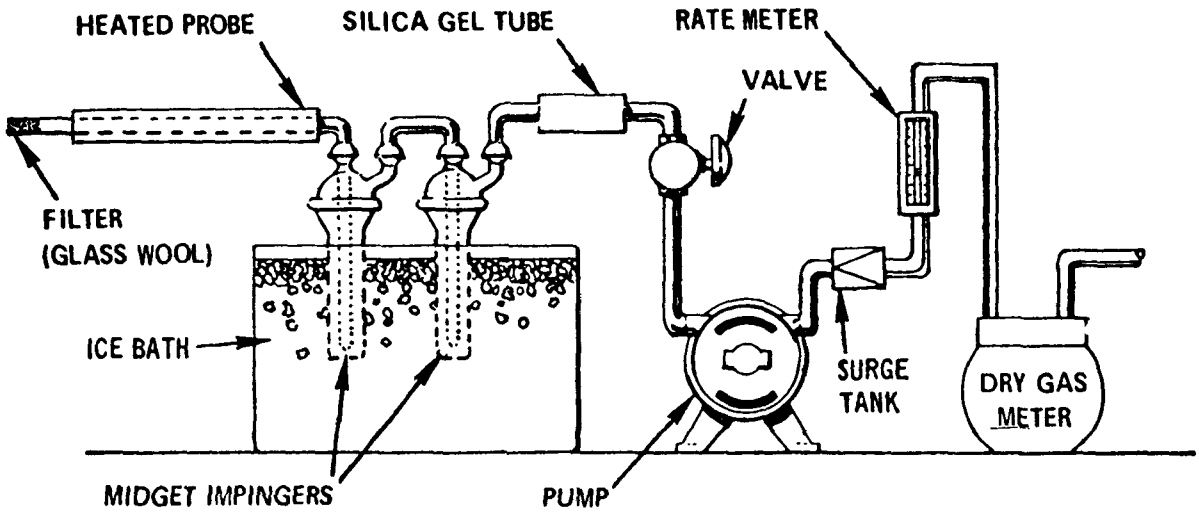


Figure 4-4. Moisture-sampling train - approximation method.

LOCATION _____ COMMENTS

TEST _____

DATE _____

OPERATOR _____

BAROMETRIC PRESSURE _____

CLOCK TIME	GAS VOLUME THROUGH METER, (Vm), m^3 (ft^3)	RATE METER SETTING m^3/min. (ft^3/min.)	METER TEMPERATURE, °C (°F)

Figure 4-5. Field moisture determination - approximation method.

2.3 Calculations Carry out the following calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

	IMPINGER VOLUME, ml	SILICA GEL WEIGHT, g
FINAL		
INITIAL		
DIFFERENCE		

Figure 4-3. Analytical data - reference method.

2.3.1 Nomenclature.

B_{ws} = Proportion of water vapor, by volume, in the gas stream.

M_w = Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).

P_m = Absolute pressure (for this method, same as barometric pressure) at the dry gas meter, mm Hg (in. Hg).

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R = Ideal gas constant, 0.06236 (mm Hg) (m³)/(g-mole) (°K) for metric units and 21.85 (in. Hg) (ft³)/(lb-mole) (°R) for English units.

T_m = Absolute temperature at meter, °K (°R).

T_{std} = Standard absolute temperature, 293° K (528° R).

V_m = Dry gas volume measured by dry gas meter, dcm (dcf).

ΔV_m = Incremental dry gas volume measured by dry gas meter at each traverse point, dcm (dcf).

$V_{m(std)}$ = Dry gas volume measured by the dry gas meter, corrected to standard conditions, dscm (dscf).

$V_{wc(std)}$ = Volume of water vapor condensed corrected to standard conditions, scm (scf).

$V_{wsg(std)}$ = Volume of water vapor collected in silica gel corrected to standard conditions, scm (scf).

V_f = Final volume of condenser water, ml.

V_i = Initial volume, if any, of condenser water, ml.

W_f = Final weight of silica gel or silica gel plus impinger, g.

W_i = Initial weight of silica gel or silica gel plus impinger, g.

Y = Dry gas meter calibration factor.

ρ_w = Density of water, 0.9982 g/ml (0.002201 lb/ml). [87]

2.3.2 Volume of water vapor condensed.

$$V_{wc(std)} = \frac{(V_f - V_i)\rho_w R T_{std}}{P_{std} M_w} = K_1 (V_f - V_i)$$

Equation 4-1

where:
K_1 = 0.001333 m³/ml for metric units
= 0.04707 ft³/ml for English units

2.3.3 Volume of water vapor collected in silica gel.

$$V_{wsg(std)} = \frac{(W_f - W_i) R T_{std}}{P_{std} M_w} = K_2 (W_f - W_i)$$

Equation 4-2

where:
K_2 = 0.001335 m³/g for metric units
= 0.04715 ft³/g for English units

2.3.4 Sample gas volume.

$$V_{m(std)} = V_m Y \frac{(P_m)(T_{std})}{(P_{std})(T_m)} = K_3 Y \frac{V_m P_m}{T_m}$$

Equation 4-3

where:
K_3 = 0.3858 °K/mm Hg for metric units
= 17.64 °R/in. Hg for English units

NOTE.—If the post-test leak rate (Section 2.2.6) exceeds the allowable rate, correct the value of V_m in Equation 4-3, as described in Section 6.3 of Method 5.

2.3.5 Moisture Content

$$B_{ws} = \frac{V_{wc(std)} + V_{wsg(std)}}{V_{wc(std)} + V_{wsg(std)} + V_{m(std)}}$$

Equation 4-4

NOTE.—In saturated or moisture droplet-laden gas streams, two calculations of the moisture content of the stack gas shall be made, one using a value based upon the saturated conditions (see Section 1.2), and another based upon the results of the impinger analysis. The lower of these two values of B_{ws} shall be considered correct.

2.3.6 Verification of constant sampling rate. For each time increment, determine the ΔV_m. Calculate the average. If the value for any time increment differs from the average by more than 10 percent, reject the results and repeat the run.

3 *Approximation Method*

The approximation method described below is presented only as a suggested method (see Section 1.2).

3.1 Apparatus.

3.1.1 Probe. Stainless steel or glass tubing, sufficiently heated to prevent water condensation and equipped with a filter (either in-stack or heated out-stack) to remove particulate matter. A plug of glass wool, inserted into the end of the probe, is a satisfactory filter.

3.1.2 Impingers. Two midget impingers, each with 30 ml capacity, or equivalent.

3.1.3 Ice Bath. Container and ice, to aid in condensing moisture in impingers.

3.1.4 Drying Tube. Tube packed with new or regenerated 6- to 16-mesh indicating-type silica gel (or equivalent desiccant), to dry the sample gas and to protect the meter and pump.

3.1.5 Valve. Needle valve, to regulate the sample gas flow rate.

3.1.6 Pump. Leak-free, diaphragm type, or equivalent, to pull the gas sample through the train.

3.1.7 Volume meter. Dry gas meter, sufficiently accurate to measure the sample volume within 2%, and calibrated over the range of flow rates and conditions actually encountered during sampling.

3.1.8 Rate Meter. Rotameter, to measure the flow range from 0 to 3 l pm (0 to 0.11 cfm). [87]

3.1.9 Graduated Cylinder. 25 ml.

3.1.10 Barometer. Mercury, aneroid, or other barometer, as described in Section 2.1.5 above.

3.1.11 Vacuum Gauge. At least 760 mm Hg (30 in. Hg) gauge, to be used for the sampling leak check.

3.2 Procedure.

3.2.1 Place exactly 5 ml distilled water in each impinger. Leak check the sampling train as follows: Temporarily insert a vacuum gauge at or near the probe inlet; then, plug the probe inlet and pull a vacuum of at least 250 mm Hg (10 in. Hg). Note, the time rate of change of the dry gas meter dial; alternatively, a rotameter (0-40 cc/min) may be temporarily attached to the dry gas meter outlet to determine the leakage rate. A leak rate not in excess of 2 percent of the average sampling rate is acceptable.

NOTE.—Carefully release the probe inlet plug before turning off the pump. [87]

3.2.2 Connect the probe, insert it into the stack, and sample at a constant rate of 2 lpm (0.071 cfm). Continue sampling until the dry gas meter registers about 30 liters (1.1 ft³) or until visible liquid droplets are carried over from the first impinger to the second. Record temperature, pressure, and dry gas meter readings as required by Figure 4-5.

3.2.3 After collecting the sample, combine the contents of the two impingers and measure the volume to the nearest 0.5 ml.

3.3 Calculations. The calculation method presented is designed to estimate the moisture in the stack gas; therefore, other data, which are only necessary for accurate moisture determinations, are not collected. The following equations adequately estimate the moisture content, for the purpose of determining isokinetic sampling rate settings.

3.3.1 Nomenclature.

B_{wm} = Approximate proportion, by volume, of water vapor in the gas stream leaving the second impinger, 0.025.

B_{ws} = Water vapor in the gas stream, proportion by volume.

M_w = Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).

P_m = Absolute pressure (for this method, same as barometric pressure) at the dry gas meter.

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R = Ideal gas constant, 0.06236 (mm Hg) (m³)/(g-mole) (°K) for metric units and 21.85 (in. Hg) (ft³)/(lb-mole) (°R) for English units.

T_m = Absolute temperature at meter, °K (°R).

T_{std} = Standard absolute temperature, 293° K (528° R).

V_f = Final volume of impinger contents, ml.

V_i = Initial volume of impinger contents, ml.

V_m = Dry gas volume measured by dry gas meter, dcm (dcf).

$V_{m(std)}$ = Dry gas volume measured by dry gas meter, corrected to standard conditions, dscm (dscf).

$V_{wc(std)}$ = Volume of water vapor condensed, corrected to standard conditions, scm (scf).

ρ_w = Density of water, 0.9982 g/ml (0.002201 lb/ml).

Y = Dry gas meter calibration factor. [87]

3.3.2 Volume of water vapor collected.

$$V_{wc} = \frac{(V_f - V_i)\rho_w R T_{std}}{P_{std} M_w} = K_1 (V_f - V_i)$$

Equation 4-5

where:
K_1 = 0.001333 m³/ml for metric units
= 0.04707 ft³/ml for English units.

3.3.3 Gas volume.

$$V_{m(std)} = V_m Y \left(\frac{P_m}{P_{std}}\right)\left(\frac{T_{std}}{T_m}\right) = K_2 Y \frac{V_m P_m}{T_m}$$

Equation 4-6 [87]

where:
K_2 = 0.3858 °K/mm Hg for metric units
= 17.64 °R/in. Hg for English units

3.3.4 Approximate moisture content.

$$B_{ws} = \frac{V_{wc(std)}}{V_{wc(std)} + V_{m(std)}} + B_{wm} \frac{V_{wc(std)}}{V_{wc(std)} + V_{m(std)}} + (0.025)$$

Equation 4-7 [87]

4. *Calibration*

4.1 For the reference method, calibrate equipment as specified in the following sections of Method 5: Section 5.3 (metering system); Section 5.5 (temperature gauges); and Section 5.7 (barometer). The recommended leak check of the metering system (Section 5.6 of Method 5) also applies to the reference method. For the approximation method, use the procedures outlined in Section 5.1.1 of Method 6 to calibrate the metering system, and the procedure of Method 5, Section 5.7 to calibrate the barometer.

5. *Bibliography*

1. Air Pollution Engineering Manual (Second Edition). Danielson, J. A. (ed.). U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, N.C. Publication No. AP-40. 1973.

2. Devorkin, Howard, et al. Air Pollution Source Testing Manual. Air Pollution Control District, Los Angeles, Calif. November, 1963.

3. Methods for Determination of Velocity, Volume, Dust and Mist Content of Gases. Western Precipitation Division of Joy Manufacturing Co., Los Angeles, Calif. Bulletin WP-50. 1968.

METHOD 5—DETERMINATION OF PARTICULATE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and Applicability*

1.1 Principle. Particulate matter is withdrawn isokinetically from the source and collected on a glass fiber filter maintained at a temperature in the range of 120±14° C (248±25° F) or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator, U.S. Environmental Protection Agency, for a particular application. The particulate mass, which includes any material that condenses at or above the filtration temperature, is determined gravimetrically after removal of uncombined water.

1.2 Applicability. This method is applicable for the determination of particulate emissions from stationary sources.

2. *Apparatus*

2.1 Sampling Train. A schematic of the sampling train used in this method is shown in Figure 5-1. Complete construction details are given in APTD-0581 (Citation 2 in Section 7); commercial models of this train are also available. For changes from APTD-0581 and for allowable modifications of the train shown in Figure 5-1, see the following subsections.

The operating and maintenance procedures for the sampling train are described in APTD-0576 (Citation 3 in Section 7). Since correct usage is important in obtaining valid results, all users should read APTD-0576 and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein. The sampling train consists of the following components:

2.1.1 Probe Nozzle. Stainless steel (316) or glass with sharp, tapered leading edge. The angle of taper shall be ≤30° and the taper shall be on the outside to preserve a constant internal diameter. The probe nozzle shall be of the button-hook or elbow design, unless otherwise specified by the Administrator. If made of stainless steel, the nozzle shall be constructed from seamless tubing; other materials of construction may be used, subject to the approval of the Administrator.

A range of nozzle sizes suitable for isokinetic sampling should be available, e.g., 0.32 to 1.27 cm (⅛ to ½ in.)—or larger if higher volume sampling trains are used—inside diameter (ID) nozzles in increments of 0.16 cm (1/16 in.). Each nozzle shall be calibrated according to the procedures outlined in Section 5.

2.1.2 Probe Liner. Borosilicate or quartz glass tubing with a heating system capable of maintaining a gas temperature at the exit end during sampling of 120±14° C (248±25° F), or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator for a particular application. (The tester may opt to operate the equipment at a temperature lower than that specified.) Since the actual temperature at the outlet of the probe is not usually monitored during sampling, probes constructed according to APTD-0581 and utilizing the calibration curves of APTD-0576 (or calibrated according to the procedure outlined in APTD-0576) will be considered acceptable.

Either borosilicate or quartz glass probe liners may be used for stack temperatures up to about 480° C (900° F); quartz liners shall be used for temperatures between 480 and 900° C (900 and 1,650° F). Both types of liners may be used at higher temperatures than specified for short periods of time, subject to the approval of the Administrator. The softening temperature for borosilicate is 820° C (1,508° F), and for quartz it is 1,500° C (2,732° F).

Whenever practical, every effort should be made to use borosilicate or quartz glass probe liners. Alternatively, metal liners (e.g., 316 stainless steel, Incoloy 825,[2] or other corrosion resistant metals) made of seamless tubing may be used, subject to the approval of the Administrator.

2.1.3 Pitot Tube. Type S, as described in Section 2.1 of Method 2, or other device approved by the Administrator. The pitot tube shall be attached to the probe (as shown in Figure 5-1) to allow constant monitoring of the stack gas velocity. The impact (high pressure) opening plane of the pitot tube shall be even with or above the nozzle entry plane (see Method 2, Figure 2-6b) during sampling. The Type S pitot tube assembly shall have a known coefficient, determined as outlined in Section 4 of Method 2.

[2] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

2.1.4 Differential Pressure Gauge. Inclined manometer or equivalent device (two), as described in Section 2.2 of Method 2. One manometer shall be used for velocity head (Δp) readings, and the other, for orifice differential pressure readings.

2.1.5 Filter Holder. Borosilicate glass, with a glass frit filter support and a silicone rubber gasket. Other materials of construction (e.g., stainless steel, Teflon, Viton) may be used, subject to approval of the Administrator. The holder design shall provide a positive seal against leakage from the outside or around the filter. The holder shall be attached immediately at the outlet of the probe (or cyclone, if used).

2.1.6 Filter Heating System. Any heating system capable of maintaining a temperature around the filter holder during sampling of 120±14° C (248±25° F), or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator for a particular application. Alternatively, the tester may opt to operate the equipment at a temperature lower than that specified. A temperature gauge capable of measuring temperature to within 3° C (5.4° F) shall be installed so that the temperature around the filter holder can be regulated and monitored during sampling. Heating systems other than the one shown in APTD-0581 may be used.

2.1.7 Condenser. The following system shall be used to determine the stack gas moisture content: Four impingers connected in series with leak-free ground glass fittings or any similar leak-free non-contaminating fittings. The first, third, and fourth impingers shall be of the Greenburg-Smith design, modified by replacing the tip with 1.3 cm (½ in.) ID glass tube extending to about 1.3 cm (½ in.) from the bottom of the flask. The second impinger shall be of the Greenburg-Smith design with the standard tip. Modifications (e.g., using flexible connections between the impingers, using materials other than glass, or using flexible vacuum lines to connect the filter holder to the condenser) may be used, subject to the approval of the Administrator. The first and second impingers shall contain known quantities of water (Section 4.1.3), the third shall be empty, and the fourth shall contain a known weight of silica gel, or equivalent desiccant. A thermometer, capable of measur-

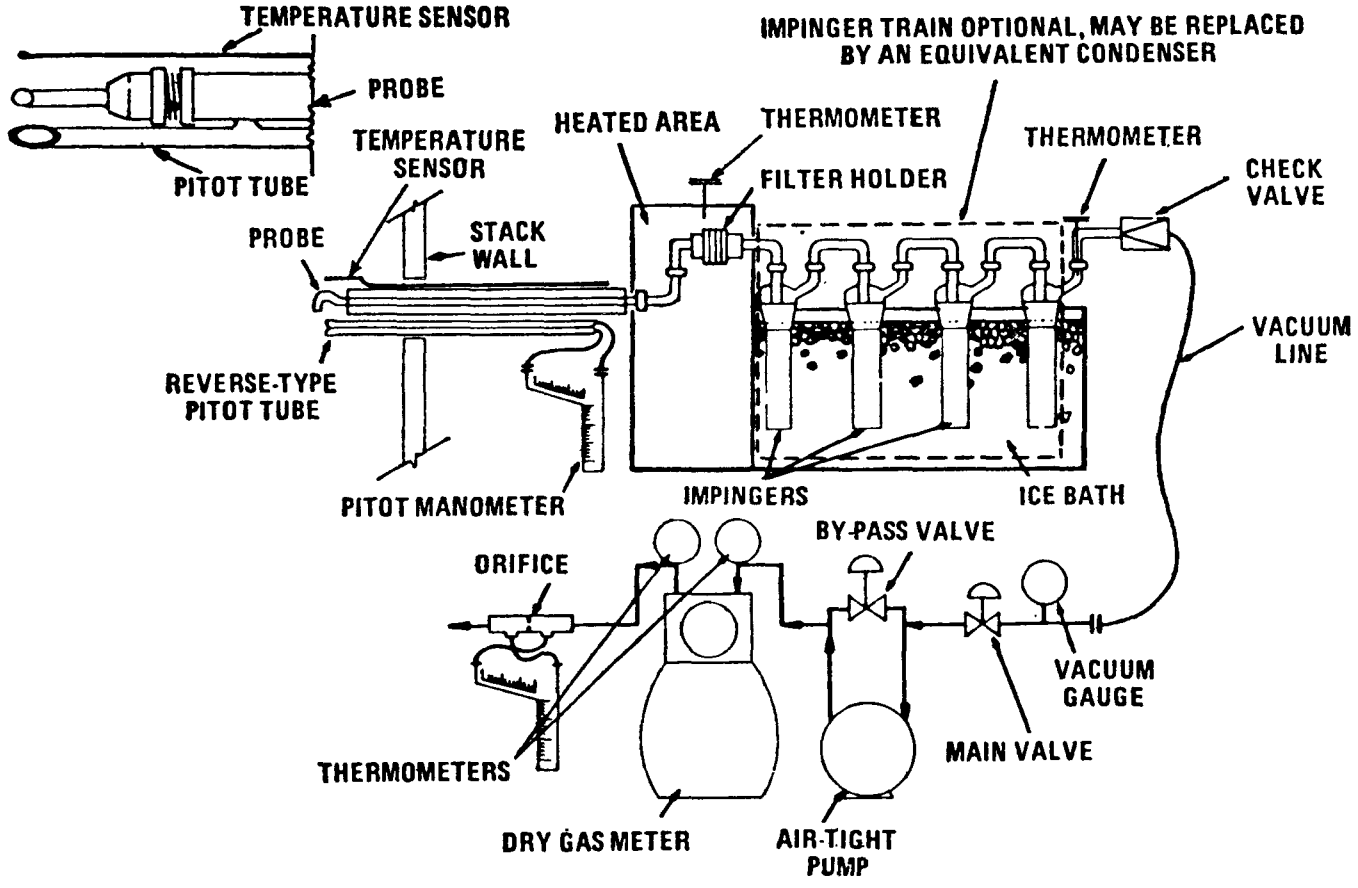


Figure 5-1. Particulate-sampling train.

ing temperature to within 1° C (2° F) shall be placed at the outlet of the fourth impinger for monitoring purposes.

Alternatively, any system that cools the sample gas stream and allows measurement of the water condensed and moisture leaving the condenser, each to within 1 ml or 1 g may be used, subject to the approval of the Administrator. Acceptable means are to measure the condensed water either gravimetrically or volumetrically and to measure the moisture leaving the condenser by: (1) monitoring the temperature and pressure at the exit of the condenser and using Dalton's law of partial pressures; or (2) passing the sample gas stream through a tared silica gel (or equivalent desiccant) trap with exit gases kept below 20° C (68° F) and determining the weight gain.

If means other than silica gel are used to determine the amount of moisture leaving the condenser, it is recommended that silica gel (or equivalent) still be used between the condenser system and pump to prevent moisture condensation in the pump and metering devices and to avoid the need to make corrections for moisture in the metered volume.

NOTE.—If a determination of the particulate matter collected in the impingers is desired in addition to moisture content, the impinger system described above shall be used, without modification. Individual States or control agencies requiring this information shall be contacted as to the sample recovery and analysis of the impinger contents.

2.1.8 Metering System. Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3° C (5.4° F), dry gas meter capable of measuring volume to within 2 percent, and related equipment, as shown in Figure 5-1. Other metering systems capable of maintaining sampling rates within 10 percent of isokinetic and of determining sample volumes to within 2 percent may be used, subject to the approval of the Administrator. When the metering system is used in conjunction with a pitot tube, the system shall enable checks of isokinetic rates.

Sampling trains utilizing metering systems designed for higher flow rates than that described in APTD-0581 or APTD-0576 may be used provided that the specifications of this method are met.

2.1.9 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.

2.1.10 Gas Density Determination Equipment. Temperature sensor and pressure gauge, as described in Sections 2.3 and 2.4 of Method 2, and gas analyzer, if necessary, as described in Method 3. The temperature sensor shall, preferably, be permanently attached to the pitot tube or sampling probe in a fixed configuration, such that the tip of the sensor extends beyond the leading edge of the probe sheath and does not touch any metal. Alternatively, the sensor may be attached just prior to use in the field. Note, however, that if the temperature sensor is attached in the field, the sensor must be placed in an interference-free arrangement with respect to the Type S pitot tube openings (see Method 2, Figure 2-7). As a second alternative, if a difference of not more than 1 percent in the average velocity measurement is to be introduced, the temperature gauge need not be attached to the probe or pitot tube. (This alternative is subject to the approval of the Administrator.)

2.2 Sample Recovery. The following items are needed.

2.2.1 Probe-Liner and Probe-Nozzle Brushes. Nylon bristle brushes with stainless steel wire handles. The probe brush shall have extensions (at least as long as the probe) of stainless steel, Nylon, Teflon, or similarly inert material. The brushes shall be properly sized and shaped to brush out the probe liner and nozzle.

2.2.2 Wash Bottles—Two. Glass wash bottles are recommended; polyethylene wash bottles may be used at the option of the tester. It is recommended that acetone not be stored in polyethylene bottles for longer than a month.

2.2.3 Glass Sample Storage Containers. Chemically resistant, borosilicate glass bottles, for acetone washes, 500 ml or 1000 ml. Screw cap liners shall either be rubber-backed Teflon or shall be constructed so as to be leak-free and resistant to chemical attack by acetone. (Narrow mouth glass bottles have been found to be less prone to leakage.) Alternatively, polyethylene bottles may be used.

2.2.4 Petri Dishes. For filter samples, glass or polyethylene, unless otherwise specified by the Administrator.[8]

2.2.5 Graduated Cylinder and/or Balance. To measure condensed water to within 1 ml or 1 g. Graduated cylinders shall have subdivisions no greater than 2 ml. Most laboratory balances are capable of weighing to the nearest 0.5 g or less. Any of these balances is suitable for use here and in Section 2.3.4.

2.2.6 Plastic Storage Containers. Air-tight containers to store silica gel.

2.2.7 Funnel and Rubber Policeman. To aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.

2.2.8 Funnel. Glass or polyethlene, to aid in sample recovery.

2.3 Analysis. For analysis, the following equipment is needed:

2.3.1 Glass Weighing Dishes.

2.3.2 Desiccator.

2.3.3 Analytical Balance. To measure to within 0.1 mg.

2.3.4 Balance. To measure to within 0.5 g.

2.3.5 Beakers. 250 ml.

2.3.6 Hygrometer. To measure the relative humidity of the laboratory environment.

2.3.7 Temperature Gauge. To measure the temperature of the laboratory environment.

3. Reagents

3.1 Sampling. The reagents used in sampling are as follows:

3.1.1 Filters. Glass fiber filters, without organic binder, exhibiting at least 99.95 percent efficiency (≤0.05 percent penetration) on 0.3-micron dioctyl phthalate smoke particles. The filter efficiency test shall be conducted in accordance with ASTM standard method D 2986-71. Test data from the supplier's quality control program are sufficient for this purpose.

3.1.2. Silica Gel. Indicating type, 6 to 16 mesh. If previously used, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to the approval of the Administrator.

3.1.3 Water. When analysis of the material caught in the impingers is required, distilled water shall be used. Run blanks prior to field use to eliminate a high blank on test samples.

3.1.4 Crushed Ice.

3.1.5 Stopcock Grease. Acetone-insoluble, heat-stable silicone grease. This is not necessary if screw-on connectors with Teflon sleeves, or similar, are used. Alternatively, other types of stopcock grease may be used, subject to the approval of the Administrator.

3.2 Sample Recovery. Acetone—reagent grade, ≤0.001 percent residue, in glass bottles—is required. Acetone from metal containers generally has a high residue blank and should not be used. Sometimes, suppliers transfer acetone to glass bottles from metal containers; thus, acetone blanks shall be run prior to field use and only acetone with low blank values (≤0.001 percent) shall be used. In no case shall a blank value of greater than 0.001 percent of the weight of acetone used be subtracted from the sample weight.

3.3 Analysis. Two reagents are required for the analysis:

3.3.1 Acetone. Same as 3.2.

3.3.2 Desiccant. Anhydrous calcium sulfate, indicating type. Alternatively, other types of desiccants may be used, subject to the approval of the Administrator.

4. Procedure

4.1 Sampling. The complexity of this method is such that, in order to obtain reliable results, testers should be trained and experienced with the test procedures.

4.1.1 Pretest Preparation. All the components shall be maintained and calibrated according to the procedure described in APTD-0576, unless otherwise specified herein.

Weigh several 200 to 300 g portions of silica gel in air-tight containers to the nearest 0.5 g. Record the total weight of the silica gel plus container, on each container. As an alternative, the silica gel need not be preweighed, but may be weighed directly in its impinger or sampling holder just prior to train assembly.

Check filters visually against light for irregularities and flaws or pinhole leaks. Label filters of the proper diameter on the back side near the edge using numbering machine ink. As an alternative, label the shipping containers (glass or plastic petri dishes) and keep the filters in these containers at all times except during sampling and weighing.

Desiccate the filters at 20±5.6° C (68±10° F) and ambient pressure for at least 24 hours and weigh at intervals of at least 6 hours to a constant weight, i.e., <0.5 mg change from previous weighing; record results to the nearest 0.1 mg. During each weighing the filter must not be exposed to the laboratory atmosphere for a period greater than 2 minutes and a relative humidity above 50 percent. Alternatively (unless otherwise specified by the Administrator), the filters may be oven dried at 105° C (220° F) for 2 to 3 hours, desiccated for 2 hours, and weighed. Procedures other than those described, which account for relative humidity effects, may be used, subject to the approval of the Administrator.

4.1.2 Preliminary Determinations. Select the sampling site and the minimum number of sampling points according to Method 1 or as specified by the Administrator. Determine the stack pressure, temperature, and the range of velocity heads using Method 2, it is recommended that a leak-check of the pitot lines (see Method 2, Section 3.1) be performed. Determine the moisture content using Approximation Method 4 or its alternatives for the purpose of making isokinetic sampling rate settings. Determine the stack gas dry molecular weight, as described in Method 2, Section 3.6; if integrated Method 3 sampling is used for molecular weight determination, the integrated bag sample shall be taken simultaneously with, and for the same total length of time as, the particulate sample run.

Select a nozzle size based on the range of velocity heads, such that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates. During the run, do not change the nozzle size. Ensure that the proper differential pressure gauge is chosen for the range of velocity heads encountered (see Section 2.2 of Method 2).

Select a suitable probe liner and probe length such that all traverse points can be sampled. For large stacks, consider sampling from opposite sides of the stack to reduce the length of probes.

Select a total sampling time greater than or equal to the minimum total sampling time specified in the test procedures for the specific industry such that (1) the sampling time per point is not less than 2 min (or some greater time interval as specified by the Administrator), and (2) the sample volume taken (corrected to standard conditions) will exceed the required minimum total gas sample volume. The latter is based on an approximate average sampling rate.

It is recommended that the number of minutes sampled at each point be an integer or an integer plus one-half minute, in order to avoid timekeeping errors. The sampling time at each point shall be the same.[8]

In some circumstances, e.g., batch cycles, it may be necessary to sample for shorter times at the traverse points and to obtain smaller gas sample volumes. In these cases, the Administrator's approval must first be obtained.

4.1.3 Preparation of Collection Train. During preparation and assembly of the sampling train, keep all openings where contamination can occur covered until just prior to assembly or until sampling is about to begin.

Place 100 ml of water in each of the first two impingers, leave the third impinger empty, and transfer approximately 200 to 300 g of preweighed silica gel from its container to the fourth impinger. More silica gel may be used, but care should be taken to ensure that it is not entrained and carried out from the impinger during sampling. Place the container in a clean place for later use in the sample recovery. Alternatively, the weight of the silica gel plus impinger may be determined to the nearest 0.5 g and recorded.

Using a tweezer or clean disposable surgical gloves, place a labeled (identified) and weighed filter in the filter holder. Be sure that the filter is properly centered and the gasket properly placed so as to prevent the sample gas stream from circumventing the filter. Check the filter for tears after assembly is completed.

When glass liners are used, install the selected nozzle using a Viton A O-ring when stack temperatures are less than 260° C (500° F) and an asbestos string gasket when temperatures are higher. See APTD-0576 for details. Other connecting systems using either 316 stainless steel or Teflon ferrules may be used. When metal liners are used, install the nozzle as above or by a leak-free direct mechanical connection. Mark the probe with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point.

Set up the train as in Figure 5-1, using (if necessary) a very light coat of silicone grease on all ground glass joints, greasing only the outer portion (see APTD-0576) to avoid possibility of contamination by the silicone grease. Subject to the approval of the Administrator, a glass cyclone may be used between the probe and filter holder when the total particulate catch is expected to exceed 100 mg or when water droplets are present in the stack gas.

Place crushed ice around the impingers.

4.1.4 Leak-Check Procedures.

4.1.4.1 Pretest Leak-Check. A pretest leak-check is recommended, but not required. If the tester opts to conduct the pretest leak-check, the following procedure shall be used.

After the sampling train has been assembled, turn on and set the filter and probe heating systems at the desired operating temperatures. Allow time for the temperatures to stabilize. If a Viton A O-ring or other leak-free connection is used in assembling the probe nozzle to the probe liner, leak-check the train at the sampling site by plugging the nozzle and pulling a 380 mm Hg (15 in. Hg) vacuum.

NOTE.—A lower vacuum may be used, provided that it is not exceeded during the test.

If an asbestos string is used, do not connect the probe to the train during the leak-check. Instead, leak-check the train by first plugging the inlet to the filter holder (cyclone, if applicable) and pulling a 380 mm Hg (15 in. Hg) vacuum (see Note immediately above). Then connect the probe to the train and leak-check at about 25 mm Hg (1 in. Hg) vacuum; alternatively, the probe may be leak-checked with the rest of the sampling train, in one step, at 380 mm Hg (15 in. Hg) vacuum. Leakage rates in excess of 4 percent of the average sampling rate or 0.00057 m^3/min (0.02 cfm), whichever is less, are unacceptable.

The following leak-check instructions for the sampling train described in APTD-0576 and APTD-0581 may be helpful. Start the pump with bypass valve fully open and coarse adjust valve completely closed. Partially open the coarse adjust valve and slowly close the bypass valve until the desired vacuum is reached. Do not reverse direction of bypass valve; this will cause water to back up into the filter holder. If the desired vacuum is exceeded, either leak-check at this higher vacuum or end the leak check as shown below and start over.

When the leak-check is completed, first slowly remove the plug from the inlet to the probe, filter holder, or cyclone (if applicable) and immediately turn off the vacuum pump. This prevents the water in the impingers from being forced backward into the filter holder and silica gel from being entrained backward into the third impinger.

4.1.4.2 Leak-Checks During Sample Run. If, during the sampling run, a component (e.g., filter assembly or impinger) change becomes necessary, a leak-check shall be conducted immediately before the change is made. The leak-check shall be done according to the procedure outlined in Section 4.1.4.1 above, except that it shall be done at a vacuum equal to or greater than the maximum value recorded up to that point in the test. If the leakage rate is found to be no greater than 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction will need to be applied to the total volume of dry gas metered; if, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and plan to correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run. 8/

Immediately after component changes, leak-checks are optional; if such leak-checks are done, the procedure outlined in Section 4.1.4.1 above shall be used.

4.1.4.3 Post-test Leak-Check. A leak-check is mandatory at the conclusion of each sampling run. The leak-check shall be done in accordance with the procedures outlined in Section 4.1.4.1, except that it shall be conducted at a vacuum equal to or greater than the maximum value reached during the sampling run. If the leakage rate is found to be no greater than 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction need be applied to the total volume of dry gas metered. If, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

4.1.5 Particulate Train Operation. During the sampling run, maintain an isokinetic sampling rate (within 10 percent of true isokinetic unless otherwise specified by the Administrator) and a temperature around the filter of 120±14° C (248±25° F), or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator.

For each run, record the data required on a data sheet such as the one shown in Figure 5-2. Be sure to record the initial dry gas meter reading. Record the dry gas meter readings at the beginning and end of each sampling time increment, when changes in flow rates are made, before and after each leak check, and when sampling is halted.

PLANT _____
LOCATION _____
OPERATOR _____
DATE _____
RUN NO. _____
SAMPLE BOX NO. _____
METER BOX NO. _____
METER ΔH@ _____
C FACTOR _____
PITOT TUBE COEFFICIENT, C_p _____

SCHEMATIC OF STACK CROSS SECTION

AMBIENT TEMPERATURE _____
BAROMETRIC PRESSURE _____
ASSUMED MOISTURE, % _____
PROBE LENGTH, m (ft) _____
NOZZLE IDENTIFICATION NO. _____
AVERAGE CALIBRATED NOZZLE DIAMETER, cm (in.) _____
PROBE HEATER SETTING _____
LEAK RATE, m^3/min. (cfm) _____
PROBE LINER MATERIAL _____
STATIC PRESSURE, mm Hg (in. Hg) _____
FILTER NO. _____

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	VACUUM mm Hg (in. Hg)	STACK TEMPERATURE (T_S) °C (°F)	VELOCITY HEAD (ΔP_S), mm(in.)H_2O	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER mm H_2O (in. H_2O)	GAS SAMPLE VOLUME m^3 (ft^3)	GAS SAMPLE TEMPERATURE AT DRY GAS METER		FILTER HOLDER TEMPERATURE, °C (°F)	TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °C (°F)
							INLET °C (°F)	OUTLET °C (°F)		
TOTAL							Avg.	Avg.		
AVERAGE							Avg.			

Figure 5-2. Particulate field data.

Take other readings required by Figure 5-2 at least once at each sample point during each time increment and additional readings when significant changes (20 percent variation in velocity head readings) necessitate additional adjustments in flow rate. Level and zero the manometer. Because the manometer level and zero may drift due to vibrations and temperature changes, make periodic checks during the traverse.

Clean the portholes prior to the test run to minimize the chance of sampling deposited material. To begin sampling, remove the nozzle cap, verify that the filter and probe heating systems are up to temperature, and that the pitot tube and probe are properly positioned. Position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. Nomographs are available, which aid in the rapid adjustment of the isokinetic sampling rate without excessive computations. These nomographs are designed for use when the Type S pitot tube coefficient is 0.85±0.02, and the stack gas equivalent density (dry molecular weight) is equal to 29±4. APTD-0576 details the procedure for using the nomographs. If C_p and M_d are outside the above stated ranges do not use the nomographs unless appropriate steps (see Citation 7 in Section 7) are taken to compensate for the deviations.

When the stack is under significant negative pressure (height of impinger stem), take care to close the coarse adjust valve before inserting the probe into the stack to prevent water from backing into the filter holder. If necessary, the pump may be turned on with the coarse adjust valve closed.

When the probe is in position, block off the openings around the probe and porthole to prevent unrepresentative dilution of the gas stream.

Traverse the stack cross-section, as required by Method 1 or as specified by the Administrator, being careful not to bump the probe nozzle into the stack walls when sampling near the walls or when removing or inserting the probe through the portholes; this minimizes the chance of extracting deposited material.

During the test run, make periodic adjustments to keep the temperature around the filter holder at the proper level; add more ice and, if necessary, salt to maintain a temperature of less than 20° C (68° F) at the condenser/silica gel outlet. Also, periodically check the level and zero of the manometer.

If the pressure drop across the filter becomes too high, making isokinetic sampling difficult to maintain, the filter may be replaced in the midst of a sample run. It is recommended that another complete filter assembly be used rather than attempting to change the filter itself. Before a new filter assembly is installed, conduct a leak-check (see Section 4.1.4.2). The total particulate weight shall include the summation of all filter assembly catches.

A single train shall be used for the entire sample run, except in cases where simultaneous sampling is required in two or more separate ducts or at two or more different locations within the same duct, or, in cases where equipment failure necessitates a change of trains. In all other situations, the use of two or more trains will be subject to the approval of the Administrator.

Note that when two or more trains are used, separate analyses of the front-half and (if applicable) impinger catches from each train shall be performed, unless identical nozzle sizes were used on all trains, in which case, the front-half catches from the individual trains may be combined (as may the impinger catches) and one analysis of front-half catch and one analysis of impinger catch may be performed. Consult with the Administrator for details concerning the calculation of results when two or more trains are used.

At the end of the sample run, turn off the coarse adjust valve, remove the probe and nozzle from the stack, turn off the pump, record the final dry gas meter reading, and conduct a post-test leak-check, as outlined in Section 4.1.4.3. Also, leak-check the pitot lines as described in Method 2, Section 3.1; the lines must pass this leak-check, in order to validate the velocity head data.

4.1.6 Calculation of Percent Isokinetic. Calculate percent isokinetic (see Calculations, Section 6) to determine whether the run was valid or another test run should be made. If there was difficulty in maintaining isokinetic rates due to source conditions, consult with the Administrator for possible variance on the isokinetic rates.

4.2 Sample Recovery. Proper cleanup procedure begins as soon as the probe is removed from the stack at the end of the sampling period. Allow the probe to cool.

When the probe can be safely handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it to prevent losing or gaining particulate matter. Do not cap off the probe tip tightly while the sampling train is cooling down as this would create a vacuum in the filter holder, thus drawing water from the impingers into the filter holder.

Before moving the sample train to the cleanup site, remove the probe from the sample train, wipe off the silicone grease, and cap the open outlet of the probe. Be careful not to lose any condensate that might be present. Wipe off the silicone grease from the filter inlet where the probe was fastened and cap it. Remove the umbilical cord from the last impinger and cap the impinger. If a flexible line is used between the first impinger or condenser and the filter holder, disconnect the line at the filter holder and let any condensed water or liquid drain into the impingers or condenser. After wiping off the silicone grease, cap off the filter holder outlet and impinger inlet. Either ground-glass stoppers, plastic caps, or serum caps may be used to close these openings.

Transfer the probe and filter-impinger assembly to the cleanup area. This area should be clean and protected from the wind so that the chances of contaminating or losing the sample will be minimized.

Save a portion of the acetone used for cleanup as a blank. Take 200 ml of this acetone directly from the wash bottle being used and place it in a glass sample container labeled "acetone blank."

Inspect the train prior to and during disassembly and note any abnormal conditions. Treat the samples as follows:

Container No. 1. Carefully remove the filter from the filter holder and place it in its identified petri dish container. Use a pair of tweezers and/or clean disposable surgical gloves to handle the filter. If it is necessary to fold the filter, do so such that the particulate cake is inside the fold. Carefully transfer to the petri dish any particulate matter and/or filter fibers which adhere to the filter holder gasket, by using a dry Nylon bristle brush and/or a sharp-edged blade. Seal the container. 87

Container No. 2. Taking care to see that dust on the outside of the probe or other exterior surfaces does not get into the sample, quantitatively recover particulate matter or any condensate from the probe nozzle, probe fitting, probe liner, and front half of the filter holder by washing these components with acetone and placing the wash in a glass container. Distilled water may be used instead of acetone when approved by the Administrator and shall be used when specified by the Administrator; in these cases, save a water blank and follow the Administrator's directions on analysis. Perform the acetone rinses as follows:

Carefully remove the probe nozzle and clean the inside surface by rinsing with acetone from a wash bottle and brushing with a Nylon bristle brush. Brush until the acetone rinse shows no visible particles, after which make a final rinse of the inside surface with acetone. 87

Brush and rinse the inside parts of the Swagelok fitting with acetone in a similar way until no visible particles remain.

Rinse the probe liner with acetone by tilting and rotating the probe while squirting acetone into its upper end so that all inside surfaces will be wetted with acetone. Let the acetone drain from the lower end into the sample container. A funnel (glass or polyethylene) may be used to aid in transferring liquid washes to the container. Follow the acetone rinse with a probe brush. Hold the probe in an inclined position, squirt acetone into the upper end as the probe brush is being pushed with a twisting action through the probe; hold a sample container underneath the lower end of the probe, and catch any acetone and particulate matter which is brushed from the probe. Run the brush through the probe three times or more until no visible particulate matter is carried out with the acetone or until none remains in the probe liner on visual inspection. With stainless steel or other metal probes, run the brush through in the above prescribed manner at least six times since metal probes have small crevices in which particulate matter can be entrapped. Rinse the brush with acetone, and quantitatively collect these washings in the sample container. After the brushing, make a final acetone rinse of the probe as described above.

It is recommended that two people be used to clean the probe to minimize sample losses. Between sampling runs, keep brushes clean and protected from contamination.

After ensuring that all joints have been wiped clean of silicone grease, clean the inside of the front half of the filter holder by rubbing the surfaces with a Nylon bristle brush and rinsing with acetone. Rinse each surface three times or more if needed to remove visible particulate. Make a final rinse of the brush and filter holder. Carefully rinse out the glass cyclone, also (if applicable). After all acetone washings and particulate matter have been collected in the sample container, tighten the lid on the sample container so that acetone will not leak out when it is shipped to the laboratory. Mark the height of the fluid level to determine whether or not leakage occurred during transport. Label the container to clearly identify its contents. 87

Container No. 3. Note the color of the indicating silica gel to determine if it has been completely spent and make a notation of its condition. Transfer the silica gel from the fourth impinger to its original container and seal. A funnel may make it easier to pour the silica gel without spilling. A rubber policeman may be used as an aid in removing the silica gel from the impinger. It is not necessary to remove the small amount of dust particles that may adhere to the impinger wall and are difficult to remove. Since the gain in weight is to be used for moisture calculations, do not use any water or other liquids to transfer the silica gel. If a balance is available in the field, follow the procedure for container No. 3 in Section 4.3.

Impinger Water. Treat the impingers as follows: Make a notation of any color or film in the liquid catch. Measure the liquid which is in the first three impingers to within ±1 ml by using a graduated cylinder or by weighing it to within ±0.5 g by using a balance (if one is available). Record the volume or weight of liquid present. This information is required to calculate the moisture content of the effluent gas.

Discard the liquid after measuring and recording the volume or weight, unless analysis of the impinger catch is required (see Note, Section 2.1.7).

If a different type of condenser is used, measure the amount of moisture condensed either volumetrically or gravimetrically.

Whenever possible, containers should be shipped in such a way that they remain upright at all times.

4.3 Analysis. Record the data required on a sheet such as the one shown in Figure 5-8. Handle each sample container as follows:

Container No. 1. Leave the contents in the shipping container or transfer the filter and any loose particulate from the sample container to a tared glass weighing dish. Desiccate for 24 hours in a desiccator containing anhydrous calcium sulfate. Weigh to a constant weight and report the results to the nearest 0.1 mg. For purposes of this Section, 4.3, the term "constant weight" means a difference of no more than 0.5 mg or 1 percent of total weight less tare weight, whichever is greater, between two consecutive weighings, with no less than 6 hours of desiccation time between weighings.

Alternatively, the sample may be oven dried at 105° C (220° F) for 2 to 3 hours, cooled in the desiccator, and weighed to a constant weight, unless otherwise specified by the Administrator. The tester may also opt to oven dry the sample at 105 ° C (220 ° F) for 2 to 3 hours, weigh the sample, and use this weight as a final weight.

Container No. 2. Note the level of liquid in the container and confirm on the analysis sheet whether or not leakage occurred during transport. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results. Measure the liquid in this container either volumetrically to ±1 ml or gravimetrically to ±0.5 g. Transfer the contents to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

Container No. 3. Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g using a balance. This step may be conducted in the field.

"Acetone Blank" Container. Measure acetone in this container either volumetrically or gravimetrically. Transfer the acetone to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a contsant weight. Report the results to the nearest 0.1 mg.

NOTE.—At the option of the tester, the contents of Container No. 2 as well as the acetone blank container may be evaporated at temperatures higher than ambient. If evaporation is done at an elevated temperature, the temperature must be below the boiling point of the solvent; also, to prevent "bumping," the evaporation process must be closely supervised, and the contents of the beaker must be swirled occasionally to maintain an even temperature. Use extreme care, as acetone is highly flammable and has a low flash point.

5. *Calibration*

Maintain a laboratory log of all calibrations.

5.1 Probe Nozzle. Probe nozzles shall be calibrated before their initial use in the field. Using a micrometer, measure the inside diameter of the nozzle to the nearest 0.025 mm (0.001 in.). Make three separate measurements using different diameters each time, and obtain the average of the measurements. The difference between the high and low numbers shall not exceed 0.1 mm (0.004 in.). When nozzles become nicked, dented, or corroded, they shall be reshaped, sharpened, and recalibrated before use. Each nozzle shall be permanently and uniquely identified.

5.2 Pitot Tube. The Type S pitot tube assembly shall be calibrated according to the procedure outlined in Section 4 of Method 2.

5.3 Metering System. Before its initial use in the field, the metering system shall be calibrated according to the procedure outlined in APTD-0576. Instead of physically adjusting the dry gas meter dial readings to correspond to the wet test meter readings, calibration factors may be used to mathematically correct the gas meter dial readings to the proper values. Before calibrating the metering system, it is suggested that a leak-check be conducted. For metering systems having diaphragm pumps, the normal leak-check procedure will not detect leakages within the pump. For these cases the following leak-check procedure is suggested: make a 10-minute calibration run at 0.00057 m³/min (0.02 cfm); at the end of the run, take the difference of the measured wet test meter and dry gas meter volumes; divide the difference by 10, to get the leak rate. The leak rate should not exceed 0.00057 m³/min (0.02 cfm).

After each field use, the calibration of the metering system shall be checked by performing three calibration runs at a single, intermediate orifice setting (based on the previous field test), with the vacuum set at the maximum value reached during the test series. To adjust the vacuum, insert a valve between the wet test meter and the inlet of the metering system. Calculate the average value of the calibration factor. If the calibration has changed by more than 5 percent, recalibrate the meter over the full range of orifice settings, as outlined in APTD-0576.

Alternative procedures, e.g., using the orifice meter coefficients, may be used, subject to the approval of the Administrator.

NOTE.—If the dry gas meter coefficient values obtained before and after a test series differ by more than 5 percent, the test series shall either be voided, or calculations for the test series shall be performed using whichever meter coefficient value (i.e., before or after) gives the lower value of total sample volume.

5.4 Probe Heater Calibration. The probe heating system shall be calibrated before its initial use in the field according to the procedure outlined in APTD-0576. Probes constructed according to APTD-0581 need not be calibrated if the calibration curves in APTD-0576 are used.

5.5 Temperature Gauges. Use the procedure in Section 4.3 of Method 2 to calibrate in-stack temperature gauges. Dial thermometers, such as are used for the dry gas meter and condenser outlet, shall be calibrated against mercury-in-glass thermometers.

5.6 Leak Check of Metering System Shown in Figure 5-1. That portion of the sampling train from the pump to the orifice meter should be leak checked prior to initial use and after each shipment. Leakage after the pump will result in less volume being recorded than is actually sampled. The following procedure is suggested (see Figure 5-4): Close the main valve on the meter box. Insert a one-hole rubber stopper with rubber tubing attached into the orifice exhaust pipe. Disconnect and vent the low side of the orifice manometer. Close off the low side orifice tap. Pressurize the system to 13 to 18 cm (5 to 7 in.) water column by blowing into the rubber tubing. Pinch off the tubing and observe the manometer for one minute. A loss of pressure on the manometer indicates a leak in the meter box; leaks, if present, must be corrected.

5.7 Barometer. Calibrate against a mercury barometer.

6. *Calculations*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after the final calculation. Other forms of the equations may be used as long as they give equivalent results.

Plant _____

Date _____

Run No. _____

Filter No. _____

Amount liquid lost during transport _____

Acetone blank volume, ml _____

Acetone wash volume, ml _____

Acetone blank concentration, mg/mg (equation 5-4) _____

Acetone wash blank, mg (equation 5-5) _____

CONTAINER NUMBER	WEIGHT OF PARTICULATE COLLECTED, mg		
	FINAL WEIGHT	TARE WEIGHT	WEIGHT GAIN
1			
2			
TOTAL			
		Less acetone blank	
		Weight of particulate matter	

	VOLUME OF LIQUID WATER COLLECTED		
	IMPINGER VOLUME, ml.	SILICA GEL WEIGHT, g	
FINAL			
INITIAL			
LIQUID COLLECTED			
TOTAL VOLUME COLLECTED		g*	ml

* CONVERT WEIGHT OF WATER TO VOLUME BY DIVIDING TOTAL WEIGHT INCREASE BY DENSITY OF WATER (1g/ml).

$$\frac{\text{INCREASE, g}}{\text{1 g/ml}} = \text{VOLUME WATER, ml}$$

Figure 5-3. Analytical data.

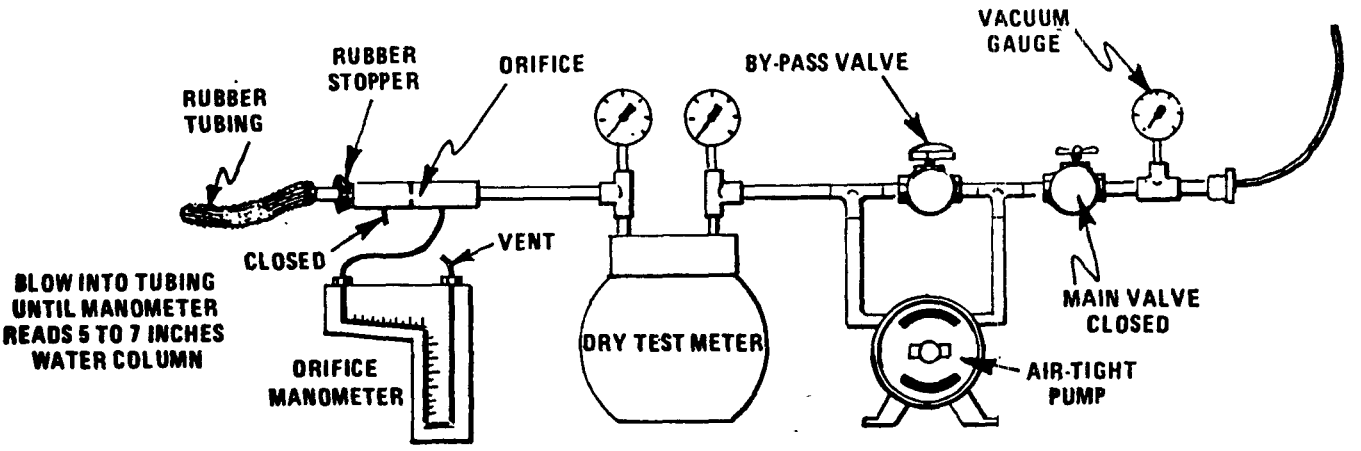


Figure 5-4. Leak check of meter box.

6.1 Nomenclature

A_n = Cross-sectional area of nozzle, m² (ft²).

B_{ws} = Water vapor in the gas stream, proportion by volume.

C_a = Acetone blank residue concentration, mg/g. 87

c_s = Concentration of particulate matter in stack gas, dry basis, corrected to standard conditions, g/dscm (g/dscf).

I = Percent of isokinetic sampling.

L_a = Maximum acceptable leakage rate for either a pretest leak check or for a leak check following a component change; equal to 0.00067 m³/min (0.02 cfm) or 4 percent of the average sampling rate, whichever is less.

L_i = Individual leakage rate observed during the leak check conducted prior to the "i^{th}" component change (i=1, 2, 3 . . . . n), m³/min (cfm).

L_p = Leakage rate observed during the post-test leak check, m³/min (cfm).

m_a = Total amount of particulate matter collected, mg.

M_w = Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).

m_a = Mass of residue of acetone after evaporation, mg.

P_{bar} = Barometric pressure at the sampling site, mm Hg (in. Hg).

P_s = Absolute stack gas pressure, mm Hg (in. Hg).

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R = Ideal gas constant, 0.06236 mm Hg-m³/°K-g-mole (21.85 in. Hg-ft³/°R-lb-mole).

T_m = Absolute average dry gas meter temperature (see Figure 5-2), °K (°R).

T_s = Absolute average stack gas temperature (see Figure 5-2), °K (°R).

T_{std} = Standard absolute temperature, 293° K (528° R).

V_a = Volume of acetone blank, ml.

V_{aw} = Volume of acetone used in wash, ml.

V_{lc} = Total volume of liquid collected in impingers and silica gel (see Figure 5-3), ml.

V_m = Volume of gas sample as measured by dry gas meter, dcm (dcf).

$V_{m(std)}$ = Volume of gas sample measured by the dry gas meter, corrected to standard conditions, dscm (dscf).

$V_{w(std)}$ = Volume of water vapor in the gas sample, corrected to standard conditions, scm (scf)

v_s = Stack gas velocity, calculated by Method 2, Equation 2-9, using data obtained from Method 5, m/sec (ft/sec). 87

W_a = Weight of residue in acetone wash, mg.

Y = Dry gas meter calibration factor.

ΔH = Average pressure differential across the orifice meter (see Figure 5-2), mm H_2O (in. H_2O).

ρ_a = Density of acetone, mg/ml (see label on bottle).

ρ_w = Density of water, 0.9982 g/ml (0.002201 lb/ml).

θ = Total sampling time, min.

θ_i = Sampling time interval, from the beginning of a run until the first component-change, min.

θ_i = Sampling time interval, between two successive component changes, beginning with the interval between the first and second changes, min.

θ_p = Sampling time interval, from the final (n^{th}) component change until the end of the sampling run, min.

13.6 = Specific gravity of mercury

60 = Sec/min.

100 = Conversion to percent.

6.2 Average dry gas meter temperature and average orifice pressure drop. See data sheet (Figure 5-2).

6.3 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20° C, 760 mm Hg or 68° F, 29.92 in. Hg) by using Equation 5-1.

$$V_{m(std)} = V_m Y \left(\frac{T_{std}}{T_m}\right)\left[\frac{P_{bar} + \frac{\Delta H}{13.6}}{P_{std}}\right]$$

$$= K_1 V_m Y \frac{P_{bar} + (\Delta H/13.6)}{T_m}$$

Equation 5-1

where:

K_1 = 0.3858 °K/mm Hg for metric units 87

= 17.64 °R/in. Hg for English units

NOTE.—Equation 5-1 can be used as written unless the leakage rate observed during any of the mandatory leak checks (i.e., the post-test leak check or leak checks conducted prior to component changes) exceeds L_a. If L_p or L_i exceeds L_a, Equation 5-1 must be modified as follows:

(a) Case I. No component changes made during sampling run. In this case, replace V_m in Equation 5-1 with the expression;

$$V_m - (L_p - L_a)\theta]$$

(b) Case II. One or more component changes made during the sampling run. In this case, replace V_m in Equation 5-1 by the expression:

$$\left[V_m - (L_1 - L_a)\theta_1 - \sum_{i=2}^{n} (L_i - L_a)\theta_i - (L_p - L_a)\theta_p\right]$$

and substitute only for those leakage rates (L_i or L_p) which exceed L_a.

6.4 Volume of water vapor.

$$V_{w(std)} = V_{lc}\left(\frac{\rho_w}{M_w}\right)\left(\frac{RT_{std}}{P_{std}}\right) = K_2 V_{lc}$$

Equation 5-2

where:

K_2 = 0.001333 m³/ml for metric units.

= 0.04707 ft³/ml for English units.

6.5 Moisture Content.

$$B_{ws} = \frac{V_{w(std)}}{V_{m(std)} + V_{w(std)}}$$

Equation 5-3

NOTE.—In saturated or water droplet-laden gas streams, two calculations of the moisture content of the stack gas shall be made, one from the impinger analysis (Equation 5-3), and a second from the assumption of saturated conditions. The lower of the two values of B_{ws} shall be considered correct. The procedure for determining the moisture content based upon assumption of saturated conditions is given in the Note of Section 1.2 of Method 4. For the purposes of this method, the average stack gas temperature from Figure 5-2 may be used to make this determination, provided that the accuracy of the in-stack temperature sensor is ± 1° C (2° F).

6.6 Acetone Blank Concentration.

$$C_a = \frac{m_a}{V_a \rho_a}$$

Equation 5-4

6.7 Acetone Wash Blank.

$$W_a = C_a V_{aw} \rho_a$$

Equation 5-5

6.8 Total Particulate Weight. Determine the total particulate catch from the sum of the weights obtained from containers 1 and 2 less the acetone blank (see Figure 5-3). NOTE.—Refer to Section 4.1.5 to assist in calculation of results involving two or more filter assemblies or two or more sampling trains.

6.9 Particulate Concentration.

$$c_s = (0.001\ g/mg)\ (m_n/V_{m(std)})$$

Equation 5-6

6.10 Conversion Factors:

From	To	Multiply by
scf	m^3	0.02832
g/ft^3	gr/ft^3	15.43
g/ft^3	lb/ft^3	2.205×10^{-3}
g/ft^3	g/m^3	35.31

6.11 Isokinetic Variation.

6.11.1 Calculation From Raw Data.

$$I = \frac{100\, T_s [K_3 V_{lc} + (V_m Y / T_m)\,(P_{bar} + \Delta H/13.6)]}{60\, \theta\, v_s P_s A_n}$$

Equation 5-7 [87]

where

$K_3 = 0.003454$ mm Hg−m^3/ml−°K for metric units
$= 0.002669$ in Hg−ft^3/ml−°R for English units.

6.11.2 Calculation From Intermediate Values.

$$I = \frac{T_s V_{m(std)} P_{std} 100}{T_{std} v_s \theta A_n P_s 60 (1 - B_{ws})}$$

$$= K_4 \frac{T_s V_{m(std)}}{P_s V_s A_n \theta (1 - B_{ws})}$$

Equation 5-8

where:

$K_4 = 4.320$ for metric units
$= 0.09450$ for English units.

6.12 Acceptable Results. If 90 percent $\leq I \leq 110$ percent, the results are acceptable. If the results are low in comparison to the standard and I is beyond the acceptable range, or, if I is less than 90 percent, the Administrator may opt to accept the results. Use Citation 4 to make judgments. Otherwise, reject the results and repeat the test.

7. *Bibliography*

1. *Addendum to Specifications for* Incinerator Testing at Federal Facilities. PHS, NCAPC. Dec. 6, 1967.

2. Martin, Robert M. Construction Details of Isokinetic Source-Sampling Equipment. Environmental Protection Agency. Research Triangle Park, N.C. APTD-0581. April, 1971.

3. Rom, Jerome J. Maintenance, Calibration, and Operation of Isokinetic Source Sampling Equipment. Environmental Protection Agency. Research Triangle Park, N.C. APTD-0576. March, 1972.

4. Smith, W. S., R. T. Shigehara, and W. F. Todd. A Method of Interpreting Stack Sampling Data. Paper Presented at the 63d Annual Meeting of the Air Pollution Control Association, St. Louis, Mo. June 14-19, 1970.

5. Smith, W. S., et al. Stack Gas Sampling Improved and Simplified With New Equipment. APCA Paper No. 67-119. 1967.

6. Specifications for Incinerator Testing at Federal Facilities. PHS, NCAPC. 1967.

7. Shigehara, R. T. Adjustments in the EPA Nomograph for Different Pitot Tube Coefficients and Dry Molecular Weights. Stack Sampling News 2:4-11. October, 1974.

8. Vollaro, R. F. A Survey of Commercially Available Instrumentation For the Measurement of Low-Range Gas Velocities. U.S. Environmental Protection Agency. Emission Measurement Branch. Research Triangle Park, N.C. November, 1976 (unpublished paper).

9. Annual Book of ASTM Standards. Part 26. Gaseous Fuels; Coal and Coke; Atmospheric Analysis. American Society for Testing and Materials. Philadelphia, Pa. 1974. pp. 617-622.

METHOD 6—DETERMINATION OF SULFUR DIOXIDE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and Applicability*

1.1 Principle. A gas sample is extracted from the sampling point in the stack. The sulfuric acid mist (including sulfur trioxide) and the sulfur dioxide are separated. The sulfur dioxide fraction is measured by the barium-thorin titration method.

1.2 Applicability. This method is applicable for the determination of sulfur dioxide emissions from stationary sources. The minimum detectable limit of the method has been determined to be 3.4 milligrams (mg) of SO_2/m^3 (2.12×10^{-7} lb/ft^3). Although no upper limit has been established, tests have shown that concentrations as high as 80,000 mg/m^3 of SO_2 can be collected efficiently in two midget impingers, each containing 15 milliliters of 3 percent hydrogen peroxide, at a rate of 1.0 lpm for 20 minutes. Based on theoretical calculations, the upper concentration limit in a 20-liter sample is about 93,300 mg/m^3.

Possible interferents are free ammonia, water-soluble cations, and fluorides. The cations and fluorides are removed by glass wool filters and an isopropanol bubbler, and hence do not affect the SO_2 analysis. When samples are being taken from a gas stream with high concentrations of very fine metallic fumes (such as in inlets to control devices), a high-efficiency glass fiber filter must be used in place of the glass wool plug (i.e., the one in the probe) to remove the cation interferents.

Free ammonia interferes by reacting with SO_2 to form particulate sulfite and by reacting with the indicator. If free ammonia is present (this can be determined by knowledge of the process and noticing white particulate matter in the probe and isopropanol bubbler), alternative methods, subject to the approval of the Administrator, U.S. Environmental Protection Agency, are required.

2. *Apparatus*

2.1 Sampling. The sampling train is shown in Figure 6-1, and component parts are discussed below. The tester has the option of substituting sampling equipment described in Method 8 in place of the midget impinger equipment of Method 6. However, the Method 8 train must be modified to include a heated filter between the probe and isopropanol impinger, and the operation of the sampling train and sample analysis must be at the flow rates and solution volumes defined in Method 8.

The tester also has the option of determining SO_2 simultaneously with particulate matter and moisture determinations by (1) replacing the water in a Method 5 impinger system with 3 percent peroxide solution, or (2) by replacing the Method 5 water impinger system with a Method 8 isopropanol-filter-peroxide system. The analysis for SO_2 must be consistent with the procedure in Method 8.87

2.1.1 Probe. Borosilicate glass, or stainless steel (other materials of construction may be used, subject to the approval of the Administrator), approximately 6-mm inside diameter, with a heating system to prevent water condensation and a filter (either in-stack or heated out-stack) to remove particulate matter, including sulfuric acid mist. A plug of glass wool is a satisfactory filter.

2.1.2 Bubbler and Impingers. One midget bubbler, with medium-coarse glass frit and borosilicate or quartz glass wool packed in top (see Figure 6-1) to prevent sulfuric acid mist carryover, and three 30-ml midget impingers. The bubbler and midget impingers must be connected in series with leak-free glass connectors. Silicone grease may be used, if necessary, to prevent leakage.

At the option of the tester, a midget impinger may be used in place of the midget bubbler.

Other collection absorbers and flow rates may be used, but are subject to the approval of the Administrator. Also, collection efficiency must be shown to be at least 99 percent for each test run and must be documented in the report. If the efficiency is found to be acceptable after a series of three tests, further documentation is not required. To conduct the efficiency test, an extra absorber must be added and analyzed separately. This extra absorber must not contain more than 1 percent of the total SO_2.

2.1.3 Glass Wool. Borosilicate or quartz.

2.1.4 Stopcock Grease. Acetone-insoluble, heat-stable silicone grease may be used, if necessary.

2.1.5 Temperature Gauge. Dial thermometer, or equivalent, to measure temperature of gas leaving impinger train to within 1° C (2° F.)

2.1.6 Drying Tube. Tube packed with 6- to 16-mesh indicating type silica gel, or equivalent, to dry the gas sample and to protect the meter and pump. If the silica gel has been used previously, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to approval of the Administrator. 87

2.1.7 Valve. Needle value, to regulate sample gas flow rate.87

2.1.8 Pump. Leak-free diaphragm pump, or equivalent, to pull gas through the train. Install a small surge tank between the pump and rate meter to eliminate the pulsation effect of the diaphragm pump on the rotameter. 87

2.1.9 Rate Meter. Rotameter, or equivalent, capable of measuring flow rate to within 2 percent of the selected flow rate of about 1000 cc/min.

2.1.10 Volume Meter. Dry gas meter, sufficiently accurate to measure the sample volume within 2 percent, calibrated at the selected flow rate and conditions actually encountered during sampling, and equipped with a temperature gauge (dial thermometer, or equivalent) capable of measuring temperature to within 3°C (5.4°F).

2.1.11 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.87

2.1.12 Vacuum Gauge and rotameter. At least 760 mm Hg (30 in. Hg) gauge, and 0-40 cc/min rotameter to be used for leak check of the sampling train.87

2.2.1 Wash bottles. Polyethylene or glass, 500 ml, two.

2.2.2 Storage Bottles. Polyethylene, 100 ml, to store impinger samples (one per sample).

2.3 Analysis.

2.3.1 Pipettes. Volumetric type, 5-ml, 20-ml (one per sample), and 25-ml sizes.

2.3.2 Volumetric Flasks. 100-ml size (one per sample) and 1000-ml size 87

2.3.3 Burettes. 5- and 50-ml sizes.

2.3.4 Erlenmeyer Flasks. 250 ml-size (one for each sample, blank, and standard).

2.3.5 Dropping Bottle. 125-ml size, to add indicator.

2.3.6 Graduated Cylinder. 100-ml size.

2.3.7 Spectrophotometer. To measure absorbance at 352 nanometers.

3. *Reagents*

Unless otherwise indicated, all reagents must conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society. Where such specifications are not available, use the best available grade.

3.1 Sampling.

3.1.1 Water. Deionized, distilled to conform to ASTM specification D1193-74, Type 3. At the option of the analyst, the $KMnO_4$ test for oxidizable organic matter may be omitted when high concentrations of organic matter are not expected to be present.

3.1.2 Isopropanol, 80 percent. Mix 80 ml of isopropanol with 20 ml of deionized, distilled water. Check each lot of isopropanol for peroxide impurities as follows: shake 10 ml of isopropanol with 10 ml of freshly prepared 10 percent potassium iodide solution. Prepare a blank by similarly treating 10 ml of distilled water. After 1 minute, read the absorbance at 352 nanometers on a spectrophotometer. If absorbance exceeds 0.1, reject alcohol for use.

Peroxides may be removed from isopropanol by redistilling or by passage through a column of activated alumina; however, reagent grade isopropanol with suitably low peroxide levels may be obtained from commercial sources. Rejection of contaminated lots may, therefore, be a more efficient procedure.

3.1.3 Hydrogen Peroxide, 3 Percent. Dilute 30 percent hydrogen peroxide 1:9 (v/v) with deionized, distilled water (30 ml is needed per sample). Prepare fresh daily.

3.1.4 Potassium Iodide Solution, 10 Percent. Dissolve 10.0 grams KI in deionized, distilled water and dilute to 100 ml. Prepare when needed.

3.2 Sample Recovery.

3.2.1 Water. Deionized, distilled, as in 3.1.1.

3.2.2 Isopropanol, 80 Percent. Mix 80 ml of isopropanol with 20 ml of deionized, distilled water.

3.3 Analysis.

3.3.1 Water. Deionized, distilled, as in 3.1.1.

3.3.2 Isopropanol, 100 percent.

3.3.3 Thorin Indicator. 1-(o-arsonophenylazo)-2-naphthol-3,6-disulfonic acid, disodium salt, or equivalent. Dissolve 0.20 g in 100 ml of deionized, distilled water.

3.3.4 Barium Perchlorate Solution, 0.0100 N. Dissolve 1.95 g of barium perchlorate trihydrate [$Ba(ClO_4)_2 \cdot 3H_2O$] in 200 ml distilled water and dilute to 1 liter with isopropanol. Alternatively, 1.22 g of [$BaCl_2 \cdot 2H_2O$] may be used instead of the perchlorate. Standardize as in Section 5.5.87

3.3.5 Sulfuric Acid Standard, 0.0100 N. Purchase or standardize to ±0.0002 N against 0.0100 N NaOH which has previously been standardized against potassium acid phthalate (primary standard grade).

4. *Procedure.*

4.1 Sampling.

4.1.1 Preparation of collection train. Measure 15 ml of 80 percent isopropanol into the midget bubbler and 15 ml of 3 percent hydrogen peroxide into each of the first two midget impingers. Leave the final midget impinger dry. Assemble the train as shown in Figure 6-1. Adjust probe heater to a temperature sufficient to prevent water condensation. Place crushed ice and water around the impingers.

4.1.2 Leak-check procedure. A leak check prior to the sampling run is optional; however, a leak check after the sampling run is mandatory. The leak-check procedure is as follows:

Temporarily attach a suitable (e.g., 0-40 cc/min) rotameter to the outlet of the dry gas meter and place a vacuum gauge at or near the probe inlet. Plug the probe inlet, pull a vacuum of at least 250 mm Hg (10 in. Hg), and note the flow rate as indicated by the rotameter. A leakage rate not in excess of 2 percent of the average sampling rate is acceptable.

NOTE: Carefully release the probe inlet plug before turning off the pump.

It is suggested (not mandatory) that the pump be leak-checked separately, either prior to or after the sampling run. If done prior to the sampling run, the pump leak-check shall precede the leak check of the sampling train described immediately above; if done after the sampling run, the pump leak-check shall follow the train leak-check. To leak check the pump, proceed as follows: Disconnect the drying tube from the probe-impinger assembly. Place a vacuum gauge at the inlet to either the drying tube or the pump, pull a vacuum of 250 mm (10 in.) Hg, plug or pinch off the outlet of the flow meter and then turn off the pump. The vacuum should remain stable for at least 30 seconds. 87

Other leak check procedures may be used, subject to the approval of the Administrator, U.S. Environmental Protection Agency. The procedure used in Method 5 is not suitable for diaphragm pumps.

4.1.3 Sample collection. Record the initial dry gas meter reading and barometric pressure. To begin sampling, position the tip of the probe at the sampling point, connect the probe to the bubbler, and start the pump. Adjust the sample flow to a constant rate of approximately 1.0 liter/min as indicated by the rotameter. Maintain this constant rate (±10 percent) during the entire sampling run. Take readings (dry gas meter, temperatures at dry gas meter and at impinger outlet and rate meter) at least every 5 minutes. Add more ice during the run to keep the temperature of the gases leaving the last impinger at 20° C (68° F) or less. At the conclusion of each run, turn off the pump, remove probe from the stack, and record the final readings. Conduct a leak check as in Section 4.1.2. (This leak check is mandatory.) If a leak is found, void the test run, or use procedures acceptable to the Administrator to adjust the sample volume for the leakage. Drain the ice bath, and purge the remaining part of the train by drawing clean ambient air through the system for 15 minutes at the sampling rate. 87

Clean ambient air can be provided by passing air through a charcoal filter or through an extra midget impinger with 15 ml of 3 percent H_2O_2. The tester may opt to simply use ambient air, without purification.

4.2 Sample Recovery. Disconnect the impingers after purging. Discard the contents of the midget bubbler. Pour the contents of the midget impingers into a leak-free polyethylene bottle for shipment. Rinse the three midget impingers and the connecting tubes with deionized, distilled water, and add the washings to the same storage container. Mark the fluid level. Seal and identify the sample container.

4.3 Sample Analysis. Note level of liquid in container, and confirm whether any sample was lost during shipment; note this on analytical data sheet. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results.

Transfer the contents of the storage container to a 100-ml volumetric flask and dilute to exactly 100 ml with deionized, distilled water. Pipette a 20-ml aliquot of this solution into a 250-ml Erlenmeyer flask, add 80 ml of 100 percent isopropanol and two to four drops of thorin indicator, and titrate to a pink endpoint using 0.0100 N barium perchlorate. Repeat and average the titration volumes. Run a blank with each series of samples. Replicate titrations must agree within 1 percent or 0.2 ml, whichever is larger.

(NOTE.—Protect the 0.0100 N barium perchlorate solution from evaporation at all times.)

5. *Calibration*

5.1 Metering System.

5.1.1 Initial Calibration. Before its initial use in the field, first leak check the metering system (drying tube, needle valve, pump, rotameter, and dry gas meter) as

follows: place a vacuum gauge at the inlet to the drying tube and pull a vacuum of 250 mm (10 in.) Hg; plug or pinch off the outlet of the flow meter, and then turn off the pump. The vacuum shall remain stable for at least 30 seconds. Carefully release the vacuum gauge before releasing the flow meter end.[8]

Next, calibrate the metering system (at the sampling flow rate specified by the method) as follows: connect an appropriately sized wet test meter (e.g., 1 liter per revolution) to the inlet of the drying tube. Make three independent calibration runs, using at least five revolutions of the dry gas meter per run. Calculate the calibration factor, Y (wet test meter calibration volume divided by the dry gas meter volume, both volumes adjusted to the same reference temperature and pressure), for each run, and average the results. If any Y value deviates by more than 2 percent from the average, the metering system is unacceptable for use. Otherwise, use the average as the calibration factor for subsequent test runs.

5.1.2 Post-Test Calibration Check. After each field test series, conduct a calibration check as in Section 5.1.1 above, except for the following variations: (a) the leak check is not to be conducted, (b) three, or more revolutions of the dry gas meter may be used, and (c) only two independent runs need be made. If the calibration factor does not deviate by more than 5 percent from the initial calibration factor (determined in Section 5.1.1), then the dry gas meter volumes obtained during the test series are acceptable. If the calibration factor deviates by more than 5 percent, recalibrate the metering system as in Section 5.1.1, and for the calculations, use the calibration factor (initial or recalibration) that yields the lower gas volume for each test run.

5.2 Thermometers. Calibrate against mercury-in-glass thermometers.

5.3 Rotameter. The rotameter need not be calibrated but should be cleaned and maintained according to the manufacturer's instruction.

5.4 Barometer. Calibrate against a mercury barometer.

5.5 Barium Perchlorate Solution. Standardize the barium perchlorate solution against 25 ml of standard sulfuric acid to which 100 ml of 100 percent isopropanol has been added.

6. *Calculations*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

6.1 Nomenclature.

C_{so_2} = Concentration of sulfur dioxide, dry basis corrected to standard conditions, mg/dscm (lb/dscf).
N = Normality of barium perchlorate titrant, milliequivalents/ml.
P_{bar} = Barometric pressure at the exit orifice of the dry gas meter, mm Hg (in. Hg).
P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).
T_m = Average dry gas meter absolute temperature, °K (°R).
T_{std} = Standard absolute temperature, 293° K (528° R).
V_a = Volume of sample aliquot titrated, ml.
V_m = Dry gas volume as measured by the dry gas meter, dcm (dcf).
$V_{m(std)}$ = Dry gas volume measured by the dry gas meter, corrected to standard conditions, dscm (dscf).
V_{soln} = Total volume of solution in which the sulfur dioxide sample is contained, 100 ml.
V_t = Volume of barium perchlorate titrant used for the sample, ml (average of replicate titrations).
V_{tb} = Volume of barium perchlorate titrant used for the blank, ml.
Y = Dry gas meter calibration factor.
32.03 = Equivalent weight of sulfur dioxide.

6.2 Dry sample gas volume, corrected to standard conditions.

$$V_{m(std)} = V_m Y \left(\frac{T_{std}}{T_m}\right)\left(\frac{P_{bar}}{P_{std}}\right) = K_1 Y \frac{V_m P_{bar}}{T_m}$$

Equation 6-1

where:

K_1 = 0.3858 °K/mm Hg for metric units.
= 17.64 °R/in. Hg for English units.

6.3 Sulfur dioxide concentration.

$$C_{SO_2} = K_2 \frac{(V_t - V_{tb})\, N\left(\frac{V_{soln}}{V_a}\right)}{V_{m(std)}}$$

Equation 6-2

where:

K_2 = 32.03 mg/meq. for metric units.
= 7.061×10⁻⁴ lb/meq. for English units.

7. *Bibliography*

1. Atmospheric Emissions from Sulfuric Acid Manufacturing Processes. U.S. DHEW, PHS, Division of Air Pollution. Public Health Service Publication No. 999-AP-13. Cincinnati, Ohio. 1965.

2. Corbett, P. F. The Determination of SO_2 and SO_3 in Flue Gases. Journal of the Institute of Fuel. *24:* 237-243, 1961.

3. Matty, R. E. and E. K. Diehl. Measuring Flue-Gas SO_2 and SO_3. Power. *101:* 94-97. November 1957.

4. Patton, W. F. and J. A. Brink, Jr. New Equipment and Techniques for Sampling Chemical Process Gases. J. Air Pollution Control Association. *13:* 162. 1963.

5. Rom, J. J. Maintenance, Calibration, and Operation of Isokinetic Source-Sampling Equipment. Office of Air Programs, Environmental Protection Agency. Research Triangle Park, N.C. APTD-0576. March 1972.

6. Hamil, H. F. and D. E. Camann. Collaborative Study of Method for the Determination of Sulfur Dioxide Emissions from Stationary Sources (Fossil-Fuel Fired Steam Generators). Environmental Protection Agency, Research Triangle Park, N.C. EPA-650/4-74-024. December 1973.

7. Annual Book of ASTM Standards. Part 31; Water, Atmospheric Analysis. American Society for Testing and Materials. Philadelphia, Pa. 1974. pp. 40-42.

8. Knoll, J. E. and M. R. Midgett. The Application of EPA Method 6 to High Sulfur Dioxide Concentrations. Environmental Protection Agency. Research Triangle Park, N.C. EPA-600/4-76-038. July 1976.

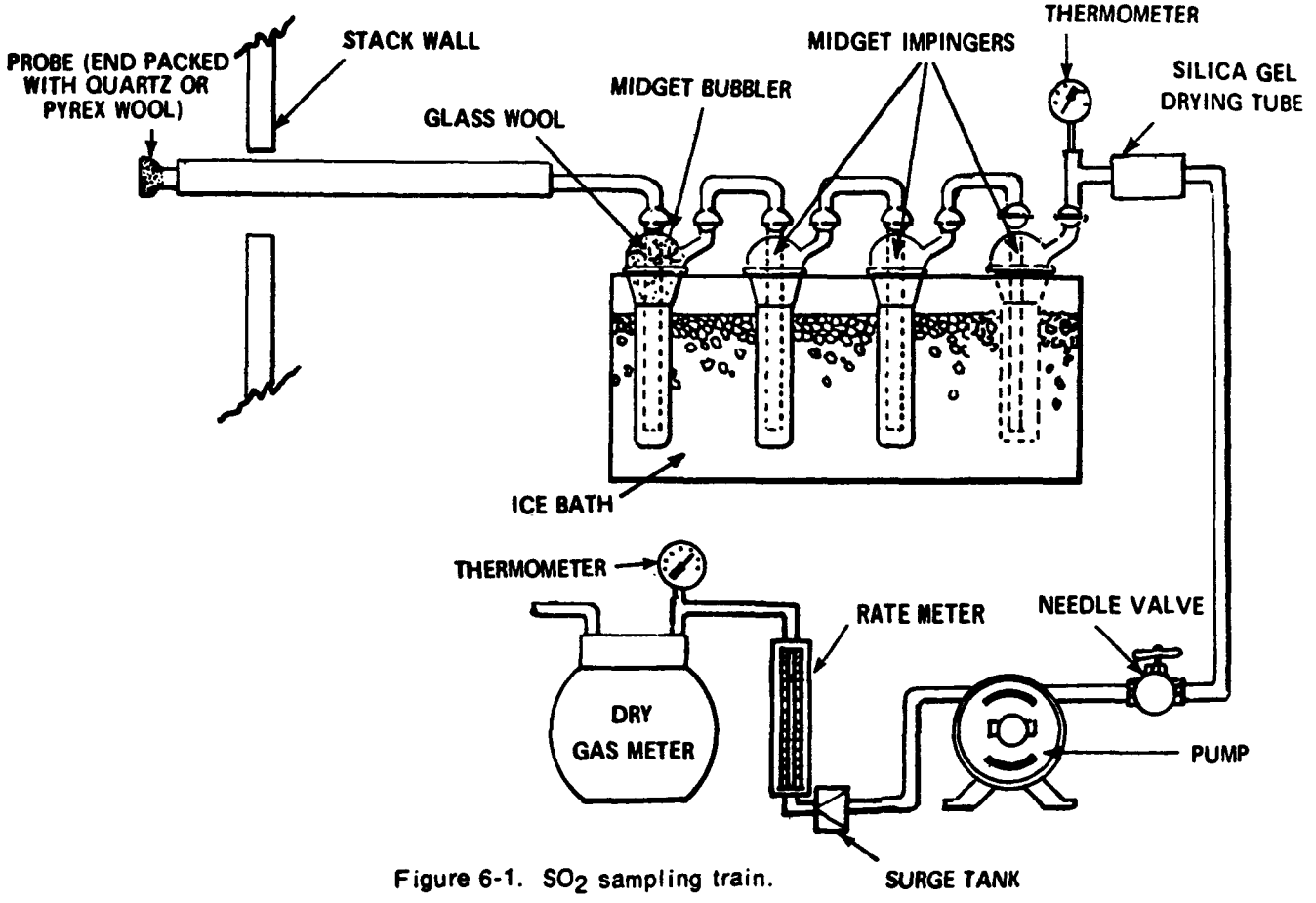


Figure 6-1. SO_2 sampling train.

METHOD 7—DETERMINATION OF NITROGEN OXIDE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and Applicability*

1.1 Principle. A grab sample is collected in an evacuated flask containing a dilute sulfuric acid-hydrogen peroxide absorbing solution, and the nitrogen oxides, except nitrous oxide, are measured colorimetrically using the phenoldisulfonic acid (PDS) procedure.

1.2 Applicability. This method is applicable to the measurement of nitrogen oxides emitted from stationary sources. The range of the method has been determined to be 2 to 400 milligrams NO_x (as NO_2) per dry standard cubic meter, without having to dilute the sample.

2. *Apparatus*

2.1 Sampling (see Figure 7-1). Other grab sampling systems or equipment, capable of measuring sample volume to within ±2.0 percent and collecting a sufficient sample volume to allow analytical reproducibility to within ±5 percent, will be considered acceptable alternatives, subject to approval of the Administrator, U.S. Environmental Protection Agency. The following equipment is used in sampling:

2.1.1 Probe. Borosilicate glass tubing, sufficiently heated to prevent water condensation and equipped with an in-stack or out-stack filter to remove particulate matter (a plug of glass wool is satisfactory for this purpose). Stainless steel or Teflon [3] tubing may also be used for the probe. Heating is not necessary if the probe remains dry during the purging period.

[3] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

2.1.2 Collection Flask. Two-liter borosilicate, round bottom flask, with short neck and 24/40 standard taper opening, protected against implosion or breakage.

2.1.3 Flask Valve. T-bore stopcock connected to a 24/40 standard taper joint.

2.1.4 Temperature Gauge. Dial-type thermometer, or other temperature gauge, capable of measuring 1° C (2° F) intervals from −5 to 50° C (25 to 125° F).

2.1.5 Vacuum Line. Tubing capable of withstanding a vacuum of 75 mm Hg (3 in. Hg) absolute pressure, with "T" connection and T-bore stopcock.

2.1.6 Vacuum Gauge. U-tube manometer, 1 meter (36 in.), with 1-mm (0.1-in.) divisions, or other gauge capable of measuring pressure to within ±2.5 mm Hg (0.10 in. Hg).

2.1.7 Pump. Capable of evacuating the collection flask to a pressure equal to or less than 75 mm Hg (3 in. Hg) absolute.

2.1.8 Squeeze Bulb. One-way.

2.1.9 Volumetric Pipette. 25 ml.

2.1.10 Stopcock and Ground Joint Grease. A high-vacuum, high-temperature chlorofluorocarbon grease is required. Halocarbon 25-5S has been found to be effective.

2.1.11 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase, or vice versa for elevation decrease.

2.2 Sample Recovery. The following equipment is required for sample recovery:

2.2.1 Graduated Cylinder. 50 ml with 1-ml divisions.

2.2.2 Storage Containers. Leak-free polyethylene bottles.

2.2.3 Wash Bottle. Polyethylene or glass.

2.2.4 Glass Stirring Rod.

2.2.5 Test Paper for Indicating pH. To cover the pH range of 7 to 14.

2.3 Analysis. For the analysis, the following equipment is needed:

2.3.1 Volumetric Pipettes. Two 1 ml, two 2 ml, one 3 ml, one 4 ml, two 10 ml, and one 25 ml for each sample and standard.

2.3.2 Porcelain Evaporating Dishes. 175- to 250-ml capacity with lip for pouring, one for each sample and each standard. The Coors No. 45006 (shallow-form, 195 ml) has been found to be satisfactory. Alternatively, polymethyl pentene beakers (Nalge No. 1203, 150 ml), or glass beakers (150 ml) may be used. When glass beakers are used, etching of the beakers may cause solid matter to be present in the analytical step; the solids should be removed by filtration (see Section 4.3). 87

2.3.3 Steam Bath. Low-temperature ovens or thermostatically controlled hot plates kept below 70° C (160° F) are acceptable alternatives.

2.3.4 Dropping Pipette or Dropper. Three required.

2.3.5 Polyethylene Policeman. One for each sample and each standard.

2.3.6 Graduated Cylinder. 100 ml with 1-ml divisions.

2.3.7 Volumetric Flasks. 50 ml (one for each sample and each standard), 100 ml (one for each sample and each standard, and one for the working standard KNO_3 solution), and 1000 ml (one). 87

2.3.8 Spectrophotometer. To measure absorbance at 410 nm.

2.3.9 Graduated Pipette. 10 ml with 0.1-ml divisions.

2.3.10 Test Paper for Indicating pH. To cover the pH range of 7 to 14.

2.3.11 Analytical Balance. To measure to within 0.1 mg.

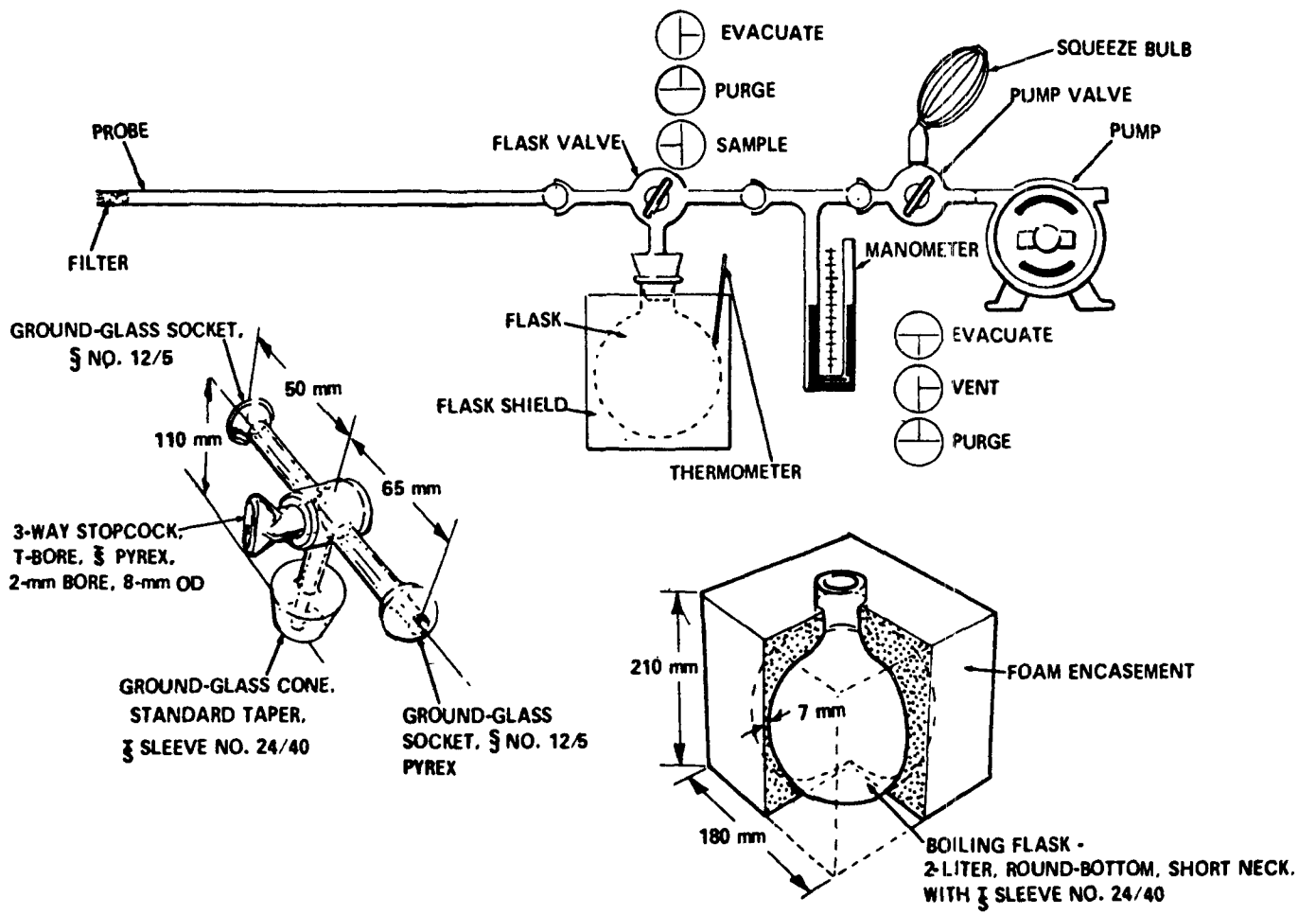


Figure 7-1. Sampling train, flask valve, and flask.

3. *Reagents*

Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

3.1 Sampling. To prepare the absorbing solution, cautiously add 2.8 ml concentrated H_2SO_4 to 1 liter of deionized, distilled water. Mix well and add 6 ml of 3 percent hydrogen peroxide, freshly prepared from 30 percent hydrogen peroxide solution. The absorbing solution should be used within 1 week of its preparation. Do not expose to extreme heat or direct sunlight

3.2 Sample Recovery. Two reagents are required for sample recovery:

3.2.1 Sodium Hydroxide (1N). Dissolve 40 g NaOH in deionized, distilled water and dilute to 1 liter.

3.2.2 Water. Deionized, distilled to conform to ASTM specification D1193-74, Type 3. At the option of the analyst, the $KMNO_4$ test for oxidizable organic matter may be omitted when high concentrations of organic matter are not expected to be present.

3.3 Analysis. For the analysis, the following reagents are required:

3.3.1 Fuming Sulfuric Acid. 15 to 18 percent by weight free sulfur trioxide. HANDLE WITH CAUTION.

3.3.2 Phenol. White solid.

3.3.3 Sulfuric Acid. Concentrated, 95 percent minimum assay. HANDLE WITH CAUTION.

3.3.4 Potassium Nitrate. Dried at 105 to 110° C (220 to 230° F) for a minimum of 2 hours just prior to preparation of standard solution.

3.3.5 Standard KNO_3 Solution. Dissolve exactly 2.198 g of dried potassium nitrate (KNO_3) in deionized, distilled water and dilute to 1 liter with deionized, distilled water in a 1,000-ml volumetric flask.

3.3.6 Working Standard KNO_3 Solution. Dilute 10 ml of the standard solution to 100 ml with deionized distilled water. One milliliter of the working standard solution is equivalent to 100 μg nitrogen dioxide (NO_2).

3.3.7 Water. Deionized, distilled as in Section 3.2.2.

3.3.8 Phenoldisulfonic Acid Solution. Dissolve 25 g of pure white phenol in 150 ml concentrated sulfuric acid on a steam bath. Cool, add 75 ml fuming sulfuric acid, and heat at 100° C (212° F) for 2 hours. Store in a dark, stoppered bottle.

4. *Procedures*

4.1 Sampling.

4.1.1 Pipette 25 ml of absorbing solution into a sample flask, retaining a sufficient quantity for use in preparing the calibration standards. Insert the flask valve stopper into the flask with the valve in the "purge" position. Assemble the sampling train as shown in Figure 7-1 and place the probe at the sampling point. Make sure that all fittings are tight and leak-free, and that all ground glass joints have been properly greased with a high-vacuum, high-temperature chlorofluorocarbon-based stopcock grease. Turn the flask valve and the pump valve to their "evacuate" positions Evacuate the flask to 75 mm Hg (3 in. Hg) absolute pressure, or less. Evacuation to a pressure approaching the vapor pressure of water at the existing temperature is desirable Turn the pump valve to its "vent" position and turn off the pump. Check for leakage by observing the manometer for any pressure fluctuation (Any variation greater than 10 mm Hg (0.4 in. Hg) over a period of 1 minute is not acceptable, and the flask is not to be used until the leakage problem is corrected. Pressure in the flask is not to exceed 75 mm Hg (3 in. Hg) absolute at the time sampling is commenced.) Record the volume of the flask and valve (V_f), the flask temperature (T_f), and the barometric pressure. Turn the flask valve counterclockwise to its "purge" position and do the same with the pump valve. Purge the probe and the vacuum tube using the squeeze bulb. If condensation occurs in the probe and the flask valve area, heat the probe and purge until the condensation disappears Next, turn the pump valve to its "vent" position. Turn the flask valve clockwise to its "evacuate" position and record the difference in the mercury levels in the manometer. The absolute internal pressure in the flask (P_f) is equal to the barometric pressure less the manometer reading Immediately turn the flask valve to the "sample" position and permit the gas to enter the flask until pressures in the flask and sample line (i.e., duct, stack) are equal. This will usually require about 15 seconds; a longer period indicates a "plug" in the probe, which must be corrected before sampling is continued After collecting the sample, turn the flask valve to its "purge" position and disconnect the flask from the sampling train. Shake the flask for at least 5 minutes.

4.1.2 If the gas being sampled contains insufficient oxygen for the conversion of NO to NO_2 (e.g., an applicable subpart of the standard may require taking a sample of a calibration gas mixture of NO in N_2), then oxygen shall be introduced into the flask to permit this conversion. Oxygen may be introduced into the flask by one of three methods; (1) Before evacuating the sampling flask, flush with pure cylinder oxygen, then evacuate flask to 75 mm Hg (3 in. Hg) absolute pressure or less; or (2) inject oxygen into the flask after sampling; or (3) terminate sampling with a minimum of 50 mm Hg (2 in. Hg) vacuum remaining in the flask, record this final pressure, and then vent the flask to the atmosphere until the flask pressure is almost equal to atmospheric pressure.

4.2 Sample Recovery Let the flask set for a minimum of 16 hours and then shake the contents for 2 minutes Connect the flask to a mercury filled U-tube manometer Open the valve from the flask to the manometer and record the flask temperature (T_f), the barometric pressure, and the difference between the mercury levels in the manometer. The absolute internal pressure in the flask (P_f) is the barometric pressure less the manometer reading. Transfer the contents of the flask to a leak-free polyethylene bottle Rinse the flask twice with 5-ml portions of deionized, distilled water and add the rinse water to the bottle. Adjust the pH to between 9 and 12 by adding sodium hydroxide (1 N), dropwise (about 25 to 35 drops) Check the pH by dipping a stirring rod into the solution and then touching the rod to the pH test paper Remove as little material as possible during this step Mark the height of the liquid level so that the container can be checked for leakage after transport Label the container to clearly identify its contents. Seal the container for shipping. 87

4.3 Analysis. Note the level of the liquid in container and confirm whether or not any sample was lost during shipment; note this on the analytical data sheet. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results. Immediately prior to analysis, transfer the contents of the shipping container to a 50-ml volumetric flask, and rinse the container twice with 5-ml portions of deionized, distilled water. Add the rinse water to the flask and dilute to the mark with deionized, distilled water; mix thoroughly. Pipette a 25-ml aliquot into the procelain evaporating dish. Return any unused portion of the sample to the polyethylene storage bottle. Evaporate the 25-ml aliquot to dryness on a steam bath and allow to cool. Add 2 ml phenoldisulfonic acid solution to the dried residue and triturate thoroughly with a polyethylene policeman. Make sure the solution contacts all the residue. Add 1 ml deionized, distilled water and four drops of concentrated sulfuric acid. Heat the solution on a steam bath for 3 minutes with occasional stirring. Allow the solution to cool, add 20 ml deionized, distilled water, mix well by stirring, and add concentrated ammonium hydroxide, dropwise, with constant stirring, until the pH is 10 (as determined by pH paper). If the sample contains solids, these must be removed by filtration (centrifugation is an acceptable alternative, subject to the approval of the Administrator), as follows: filter through Whatman No. 41 filter paper into a 100-ml volumetric flask; rinse the evaporating dish with three 5-ml portions of deionized, distilled water; filter these three rinses. Wash the filter with at least three 15-ml portions of deionized, distilled water. Add the filter washings to the contents of the volumetric flask and dilute to the mark with deionized, distilled water. If solids are absent, the solution can be transferred directly to the 100-ml volumetric flask and diluted to the mark with deionized, distilled water. Mix the contents of the flask thoroughly, and measure the absorbance at the optimum wavelength used for the standards (Section 5.2.1), using the blank solution as a zero reference. Dilute the sample and the blank with equal volumes of deionized, distilled water if the absorbance exceeds A_4, the absorbance of the 400 μg NO_2 standard (see Section 5.2.2). 87

5. *Calibration*

5.1 Flask Volume The volume of the collection flask-flask valve combination must be known prior to sampling. Assemble the flask and flask valve and fill with water, to the stopcock Measure the volume of water to ±10 ml. Record this volume on the flask.

5.2 Spectrophotometer Calibration.

5.2.1 Optimum Wavelength Determination. Calibrate the wavelength scale of the spectrophotometer every 6 months. The calibration may be accomplished by using an energy source with an intense line emission such as a mercury lamp, or by using a series of glass filters spanning the measuring range of the spectrophotometer. Calibration materials are available commercially and from the National Bureau of Standards. Specific details on the use of such materials should be supplied by the vendor; general information about calibration techniques can be obtained from general reference books on analytical chemistry. The wavelength scale of the spectrophotometer must read correctly within ± 5 nm at all calibration points; otherwise, the spectrophotometer shall be repaired and recalibrated. Once the wavelength scale of the spectrophotometer is in proper calibration, use 410 nm as the optimum wavelength for the measurement of the absorbance of the standards and samples. 87

Alternatively, a scanning procedure may be employed to determine the proper measuring wavelength. If the instrument is a double-beam spectrophotometer, scan the spectrum between 400 and 415 nm using a 200 μg NO_2 standard solution in the sample cell and a blank solution in the reference cell. If a peak does not occur, the spectrophotometer is probably malfunctioning and should be repaired. When a peak is obtained within the 400 to 415 nm range, the wavelength at which this peak occurs shall be the optimum wavelength for the measurement of absorbance of both the standards and the samples. For a single-beam spectrophotometer, follow the scanning procedure described above, except that the blank and standard solutions shall be scanned separately. The optimum wavelength shall be the wavelength at which the maximum difference in absorbance between the standard and the blank occurs. 87

5.2.2 Determination of Spectrophotometer Calibration Factor K_c. Add 0.0 ml, 2 ml, 4 ml, 6 ml, and 8 ml of the KNO_3 working standard solution (1 ml = 100 μg NO_2) to a series of five 50-ml volumetric flasks. To each flask, add 25 ml of absorbing solution, 10 ml deionized, distilled water, and sodium hydroxide (1 N) dropwise until the pH is between 9 and 12 (about 25 to 35 drops each). Dilute to the mark with deionized, distilled water. Mix thoroughly and pipette a 25-ml aliquot of each solution into a separate porcelain evaporating dish. 87

Beginning with the evaporation step, follow the analysis procedure of Section 4.3, until the solution has been transferred to the 100 ml volumetric flask and diluted to the mark Measure the absorbance of each solution, at the optimum wavelength, as determined in Section 5.2.1. This calibration procedure must be repeated on each day that samples are analyzed. Calculate the spectrophotometer calibration factor as follows.

$$K_c = 100\,\frac{A_1 + 2A_2 + 3A_3 + 4A_4}{A_1^2 + A_2^2 + A_3^2 + A_4^2}$$

Equation 7-1

where:

K_c = Calibration factor

A_1 = Absorbance of the 100-μg NO_2 standard

A_2 = Absorbance of the 200-μg NO_2 standard

A_3 = Absorbance of the 300-μg NO_2 standard

A_4 = Absorbance of the 400-μg NO_2 standard

5.3 Barometer. Calibrate against a mercury barometer.

5.4 Temperature Gauge. Calibrate dial thermometers against mercury-in-glass thermometers.

5.5 Vacuum Gauge. Calibrate mechanical gauges, if used, against a mercury manometer such as that specified in 2.1.6.

5.6 Analytical Balance. Calibrate against standard weights.

6. *Calculations*

Carry out the calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculations.

6.1 Nomenclature.

A = Absorbance of sample.

C = Concentration of NO_x as NO_2, dry basis, corrected to standard conditions, mg/dscm (lb/dscf)

F = Dilution factor (i e., 25/5, 25/10, etc., required only if sample dilution was needed to reduce the absorbance into the range of calibration).

K_c = Spectrophotometer calibration factor

m = Mass of NO_x as NO_2 in gas sample, μg. 87

P_f = Final absolute pressure of flask, mm Hg (in. Hg)

P_i = Initial absolute pressure of flask, mm Hg (in. Hg)

P_{std} = Standard absolute pressure, 760 mm Hg (29 92 in. Hg).

T_f = Final absolute temperature of flask ,°K (°R).

T_i = Initial absolute temperature of flask, °K (°R).

T_{std} = Standard absolute temperature, 293° K (528° R)

V_{sc} = Sample volume at standard conditions (dry basis), ml

V_f = Volume of flask and valve, ml.

V_a = Volume of absorbing solution, 25 ml

2 = 50/25, the aliquot factor. (If other than a 25-ml aliquot was used for analysis, the corresponding factor must be substituted).

6.2 Sample volume, dry basis, corrected to standard conditions

$$V_{sc} = \frac{T_{std}}{P_{std}}\,(V_f - V_a)\left[\frac{P_f}{T_f} - \frac{P_i}{T_i}\right]$$

$$= K_1(V_f - 25\text{ ml})\left[\frac{P_f}{T_f} - \frac{P_i}{T_i}\right]$$

Equation 7-2

where:

$$K_1 = 0.3858\,\frac{°K}{\text{mm Hg}}\text{ for metric units}$$

$$= 17.64\,\frac{°R}{\text{in. Hg}}\text{ for English units}$$

6.3 Total μg NO_2 per sample.

$$m = 2 K_c A F$$

Equation 7–3

NOTE.—If other than a 25-ml aliquot is used for analysis, the factor 2 must be replaced by a corresponding factor.

6.4 Sample concentration, dry basis, corrected to standard conditions.

$$C = K_2 \frac{m}{V_{sc}}$$

Equation 7–4

where:

$$K_2 = 10^3 \frac{mg/m^3}{\mu g/ml} \text{ for metric units}$$

$$= 6.243 \times 10^{-5} \frac{lb/scf}{\mu g/ml} \text{ for English units}$$

7. *Bibliography*

1. Standard Methods of Chemical Analysis. 6th ed. New York, D. Van Nostrand Co., Inc. 1962. Vol. 1, p. 329–330. 87

2. Standard Method of Test for Oxides of Nitrogen in Gaseous Combustion Products (Phenoldisulfonic Acid Procedure). In: 1968 Book of ASTM Standards, Part 26. Philadelphia, Pa. 1968. ASTM Designation D–1608–60, p. 725–729.

3. Jacob, M. B. The Chemical Analysis of Air Pollutants. New York. Interscience Publishers, Inc. 1960. Vol. 10, p. 351–356.

4. Beatty, R. L., L. B. Berger, and H. H. Schrenk. Determination of Oxides of Nitrogen by the Phenoldisulfonic Acid Method. Bureau of Mines, U.S. Dept. of Interior. R. I. 3687. February 1943.

5. Hamil, H. F. and D. E. Camann. Collaborative Study of Method for the Determination of Nitrogen Oxide Emissions from Stationary Sources (Fossil Fuel-Fired Steam Generators). Southwest Research Institute report for Environmental Protection Agency. Research Triangle Park, N.C. October 5, 1973.

6. Hamil, H. F. and R. E. Thomas. Collaborative Study of Method for the Determination of Nitrogen Oxide Emissions from Stationary Sources (Nitric Acid Plants). Southwest Research Institute report for Environmental Protection Agency. Research Triangle Park, N.C. May 8, 1974. 87

METHOD 8—DETERMINATION OF SULFURIC ACID MIST AND SULFUR DIOXIDE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and Applicability*

1.1 Principle. A gas sample is extracted isokinetically from the stack. The sulfuric acid mist (including sulfur trioxide) and the sulfur dioxide are separated, and both fractions are measured separately by the barium-thorin titration method.

1.2 Applicability. This method is applicable for the determination of sulfuric acid mist (including sulfur trioxide, and in the absence of other particulate matter) and sulfur dioxide emissions from stationary sources. Collaborative tests have shown that the minimum detectable limits of the method are 0.05 milligrams/cubic meter (0.03×10^{-7} pounds/cubic foot) for sulfur trioxide and 1.2 mg/m³ (0.74×10^{-7} lb/ft³) for sulfur dioxide. No upper limits have been established. Based on theoretical calculations for 200 milliliters of 3 percent hydrogen peroxide solution, the upper concentration limit for sulfur dioxide in a 1.0 m³ (35.3 ft³) gas sample is about 12,500 mg/m³ (7.7×10^{-4} lb/ft³). The upper limit can be extended by increasing the quantity of peroxide solution in the impingers.

Possible interfering agents of this method are fluorides, free ammonia, and dimethyl aniline. If any of these interfering agents are present (this can be determined by knowledge of the process), alternative methods, subject to the approval of the Administrator, U S EPA are required. [87]

Filterable particulate matter may be determined along with SO_3 and SO_2 (subject to the approval of the Administrator) by inserting a heated glass fiber filter between the probe and isopropanol impinger (see Section 2.1 of Method 6). If this option is chosen, particulate analysis is gravimetric only. H_2SO_4 acid mist is not determined separately. [87]

2. *Apparatus*

2.1 Sampling. A schematic of the sampling train used in this method is shown in Figure 8-1; it is similar to the Method 5 train except that the filter position is different and the filter holder does not have to be heated. Commercial models of this train are available. For those who desire to build their own, however, complete construction details are described in APTD-0581. Changes from the APTD-0581 document and allowable modifications to Figure 8-1 are discussed in the following subsections.

The operating and maintenance procedures for the sampling train are described in APTD-0576. Since correct usage is important in obtaining valid results, all users should read the APTD-0576 document and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein. Further details and guidelines on operation and maintenance are given in Method 5 and should be read and followed whenever they are applicable.

2.1.1 Probe Nozzle. Same as Method 5, Section 2.1.1.

2.1.2 Probe Liner. Borosilicate or quartz glass, with a heating system to prevent visible condensation during sampling. Do not use metal probe liners.

2.1.3 Pitot Tube. Same as Method 5, Section 2.1.3.

2.1.4 Differential Pressure Gauge. Same as Method 5, Section 2.1.4.

2.1.5 Filter Holder. Borosilicate glass, with a glass frit filter support and a silicone rubber gasket. Other gasket materials, e.g., Teflon or Viton, may be used subject to the approval of the Administrator. The holder design shall provide a positive seal against leakage from the outside or around the filter. The filter holder shall be placed between the first and second impingers. Note: Do not heat the filter holder.

2.1.6 Impingers—Four, as shown in Figure 8-1. The first and third shall be of the Greenburg-Smith design with standard tips. The second and fourth shall be of the Greenburg-Smith design, modified by replacing the insert with an approximately 13 millimeter (0.5 in.) ID glass tube, having an unconstricted tip located 13 mm (0.5 in.) from the bottom of the flask. Similar collection systems, which have been approved by the Administrator, may be used.

2.1.7 Metering System. Same as Method 5, Section 2.1.8.

2.1.8 Barometer. Same as Method 5, Section 2.1.9.

2.1.9 Gas Density Determination Equipment. Same as Method 5, Section 2.1.10.

2.1.10 Temperature Gauge. Thermometer, or equivalent, to measure the temperature of the gas leaving the impinger train to within 1° C (2° F).

2.2 Sample Recovery.

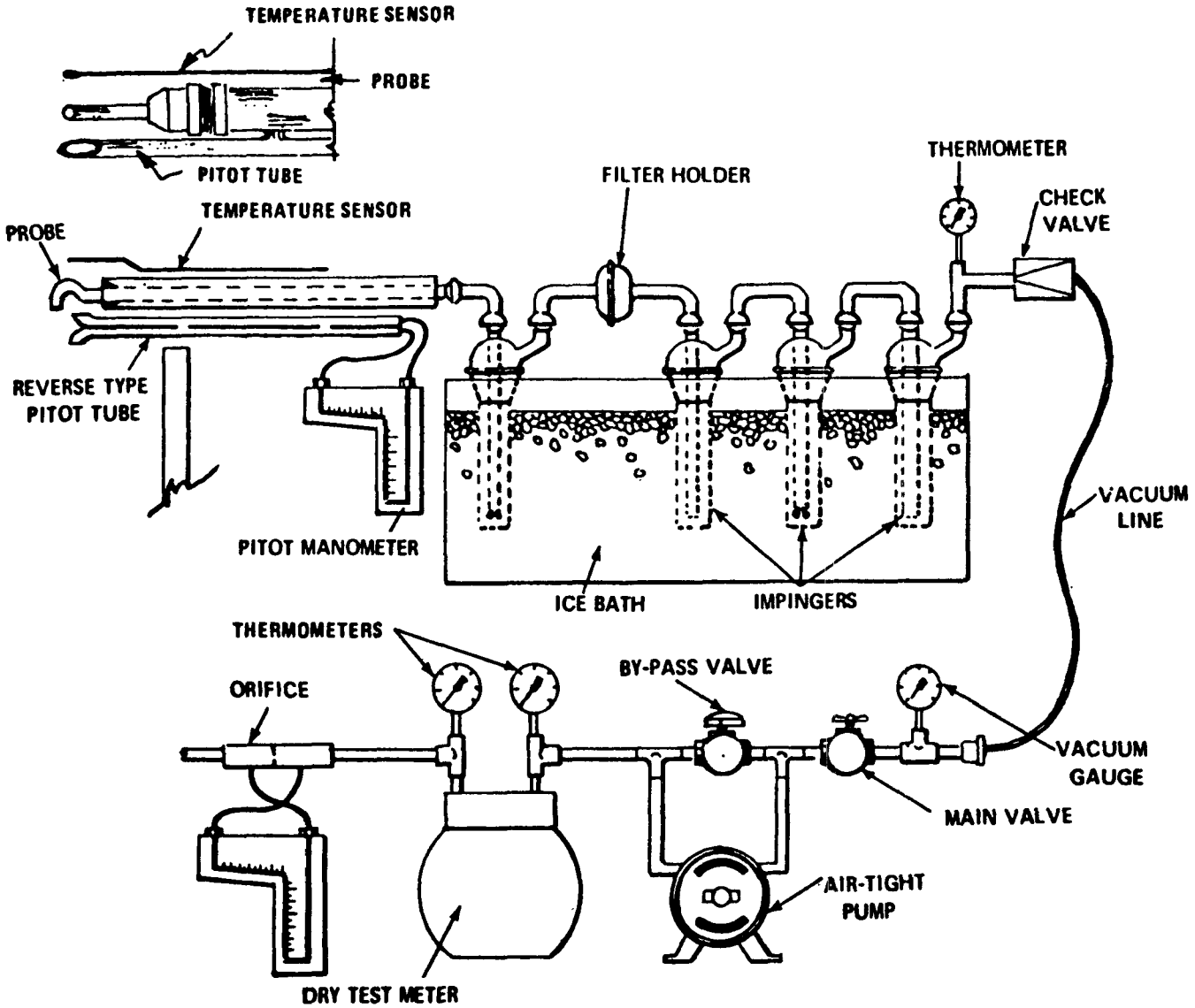


Figure 8-1. Sulfuric acid mist sampling train.

2.2.1 Wash Bottles. Polyethylene or glass, 500 ml. (two).

2.2.2 Graduated Cylinders. 250 ml, 1 liter. (Volumetric flasks may also be used.)

2.2.3 Storage Bottles. Leak-free polyethylene bottles, 1000 ml size (two for each sampling run).

2.2.4 Trip Balance. 500-gram capacity, to measure to ±0.5 g (necessary only if a moisture content analysis is to be done).

2.3 Analysis.

2.3.1 Pipettes. Volumetric 25 ml, 100 ml.

2.3.2 Burette. 50 ml.

2.3.3 Erlenmeyer Flask. 250 ml. (one for each sample blank and standard).

2.3.4 Graduated Cylinder. 100 ml.

2.3.5 Trip Balance. 500 g capacity, to measure to ±0.5 g.

2.3.6 Dropping Bottle. To add indicator solution, 125-ml size.

3. *Reagents*

Unless otherwise indicated, all reagents are to conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available. Otherwise, use the best available grade.

3.1 Sampling.

3.1.1 Filters. Same as Method 5, Section 3.1.1.

3.1.2 Silica Gel. Same as Method 5, Section 3.1.2.

3.1.3 Water. Deionized, distilled to conform to ASTM specification D1193-74, Type 3. At the option of the analyst, the $KMnO_4$ test for oxidizable organic matter may be omitted when high concentrations of organic matter are not expected to be present.

3.1.4 *Isopropanol, 80 Percent.* Mix 800 ml of isopropanol with 200 ml of deionized, distilled water.

NOTE.—Experience has shown that only A.C.S. grade isopropanol is satisfactory. Tests have shown that isopropanol obtained from commercial sources occasionally has peroxide impurities that will cause erroneously high sulfuric acid mist measurement. Use the following test for detecting peroxides in each lot of isopropanol: Shake 10 ml of the isopropanol with 10 ml of freshly prepared 10 percent potassium iodide solution. Prepare a blank by similarly treating 10 ml of distilled water. After 1 minute, read the absorbance on a spectrophotometer at 352 nanometers. If the absorbance exceeds 0.1, the isopropanol shall not be used. Peroxides may be removed from isopropanol by redistilling, or by passage through a column of activated alumina. However, reagent-grade isopropanol with suitably low peroxide levels is readily available from commercial sources; therefore, rejection of contaminated lots may be more efficient than following the peroxide removal procedure.

3.1.5 Hydrogen Peroxide, 3 Percent. Dilute 100 ml of 30 percent hydrogen peroxide to 1 liter with deionized, distilled water. Prepare fresh daily.

3.1.6 Crushed Ice.

3.2 Sample Recovery.

3.2.1 Water. Same as 3.1.3.

3.2.2 Isopropanol, 80 Percent. Same as 3.1.4.

3.3 Analysis.

3.3.1 Water. Same as 3.1.3.

3.3.2 Isopropanol, 100 Percent.

3.3.3 Thorin Indicator. 1-(o-arsonophenylazo)-2-naphthol-3, 6-disulfonic acid, disodium salt, or equivalent. Dissolve 0.20 g in 100 ml of deionized, distilled water.

3.3.4 Barium Perchlorate (0.0100 Normal). Dissolve 1.95 g of barium perchlorate trihydrate ($Ba(ClO_4)_2 \cdot 3H_2O$) in 200 ml deionized, distilled water, and dilute to 1 liter with isopropanol; 1.22 g of barium chloride dihydrate ($BaCl_2 \cdot 2H_2O$) may be used instead of the barium perchlorate. Standardize with sulfuric acid as in Section 5.2. This solution must be protected against evaporation at all times.

3.3.5 Sulfuric Acid Standard (0.0100 N). Purchase or standardize to ±0.0002 N against 0.0100 N NaOH that has previously been standardized against primary standard potassium acid phthalate.

4. *Procedure*

4.1 Sampling.

4.1.1 Pretest Preparation. Follow the procedure outlined in Method 5, Section 4.1.1; filters should be inspected, but need not be desiccated, weighed, or identified. If the effluent gas can be considered dry, i.e., moisture free, the silica gel need not be weighed.

4.1.2 Preliminary Determinations. Follow the procedure outlined in Method 5, Section 4.1.2.

4.1.3 Preparation of Collection Train. Follow the procedure outlined in Method 5, Section 4.1.3 (except for the second paragraph and other obviously inapplicable parts) and use Figure 8-1 instead of Figure 5-1. Replace the second paragraph with: Place 100 ml of 80 percent isopropanol in the first impinger, 100 ml of 3 percent hydrogen peroxide in both the second and third impingers; retain a portion of each reagent for use as a blank solution. Place about 200 g of silica gel in the fourth impinger.

PLANT _____

LOCATION _____

OPERATOR _____

DATE _____

RUN NO. _____

SAMPLE BOX NO. _____

METER BOX NO. _____

METER ΔH@ _____

C FACTOR _____

PITOT TUBE COEFFICIENT, Cp _____

SCHEMATIC OF STACK CROSS SECTION

STATIC PRESSURE, mm Hg (in. Hg) _____

AMBIENT TEMPERATURE _____

BAROMETRIC PRESSURE _____

ASSUMED MOISTURE, % _____

PROBE LENGTH, m (ft) _____

NOZZLE IDENTIFICATION NO. _____

AVERAGE CALIBRATED NOZZLE DIAMETER, cm (in.) _____

PROBE HEATER SETTING _____

LEAK RATE, m^3/min, (cfm) _____

PROBE LINER MATERIAL _____

FILTER NO. _____

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	VACUUM mm Hg (in. Hg)	STACK TEMPERATURE (Ts), °C (°F)	VELOCITY HEAD (ΔPs), mm H_2O (in. H_2O)	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER, mm H_2O (in. H_2O)	GAS SAMPLE VOLUME, m^3 (ft^3)	GAS SAMPLE TEMPERATURE AT DRY GAS METER		TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °C (°F)
							INLET, °C (°F)	OUTLET, °C (°F)	
TOTAL							Avg	Avg	
AVERAGE							Avg		

Figure 8-2. Field data.

NOTE.—If moisture content is to be determined by impinger analysis, weigh each of the first three impingers (plus absorbing solution) to the nearest 0.5 g and record these weights. The weight of the silica gel (or silica gel plus container) must also be determined to the nearest 0.5 g and recorded.

4.1.4 Pretest Leak-Check Procedure. Follow the basic procedure outlined in Method 5, Section 4.1.4.1, noting that the probe heater shall be adjusted to the minimum temperature required to prevent condensation, and also that verbage such as, "· · · plugging the inlet to the filter holder · · ·," shall be replaced by, "· · · plugging the inlet to the first impinger · · ·." The pretest leak-check is optional. [87]

4.1.5 Train Operation. Follow the basic procedures outlined in Method 5, Section 4.1.5, in conjunction with the following special instructions. Data shall be recorded on a sheet similar to the one in Figure 8-2. The sampling rate shall not exceed 0.030 m³/min (1.0 cfm) during the run. Periodically during the test, observe the connecting line between the probe and first impinger for signs of condensation. If it does occur, adjust the probe heater setting upward to the minimum temperature required to prevent condensation. If component changes become necessary during a run, a leak-check shall be done immediately before each change, according to the procedure outlined in Section 4.1.4.2 of Method 5 (with appropriate modifications, as mentioned in Section 4.1.4 of this method); record all leak rates. If the leakage rate(s) exceed the specified rate, the tester shall either void the run or shall plan to correct the sample volume as outlined in Section 6.3 of Method 5. Immediately after component changes, leak-checks are optional. If these leak-checks are done, the procedure outlined in Section 4.1.4.1 of Method 5 (with appropriate modifications) shall be used.

After turning off the pump and recording the final readings at the conclusion of each run, remove the probe from the stack. Conduct a post-test (mandatory) leak-check as in Section 4.1.4.3 of Method 5 (with appropriate modification) and record the leak rate. If the post-test leakage rate exceeds the specified acceptable rate, the tester shall either correct the sample volume, as outlined in Section 6.3 of Method 5, or shall void the run.

Drain the ice bath and, with the probe disconnected, purge the remaining part of the train, by drawing clean ambient air through the system for 15 minutes at the average flow rate used for sampling.

NOTE.—Clean ambient air can be provided by passing air through a charcoal filter. At the option of the tester, ambient air (without cleaning) may be used.

4.1.6 Calculation of Percent Isokinetic. Follow the procedure outlined in Method 5, Section 4.1.6.

4.2 Sample Recovery.

4.2.1 Container No. 1. If a moisture content analysis is to be done, weigh the first impinger plus contents to the nearest 0.5 g and record this weight.

Transfer the contents of the first impinger to a 250-ml graduated cylinder. Rinse the probe, first impinger, all connecting glassware before the filter, and the front half of the filter holder with 80 percent isopropanol. Add the rinse solution to the cylinder. Dilute to 250 ml with 80 percent isopropanol. Add the filter to the solution, mix, and transfer to the storage container. Protect the solution against evaporation. Mark the level of liquid on the container and identify the sample container. [87]

4.2.2 Container No. 2. If a moisture content analysis is to be done, weigh the second and third impingers (plus contents) to the nearest 0.5 g and record these weights. Also, weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g.

Transfer the solutions from the second and third impingers to a 1000-ml graduated cylinder. Rinse all connecting glassware (including back half of filter holder) between the filter and silica gel impinger with deionized, distilled water, and add this rinse water to the cylinder. Dilute to a volume of 1000 ml with deionized, distilled water. Transfer the solution to a storage container. Mark the level of liquid on the container. Seal and identify the sample container.

4.3 Analysis.

Note the level of liquid in containers 1 and 2, and confirm whether or not any sample was lost during shipment; note this on the analytical data sheet. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results.

4.3.1 Container No. 1. Shake the container holding the isopropanol solution and the filter. If the filter breaks up, allow the fragments to settle for a few minutes before removing a sample. Pipette a 100-ml aliquot of this solution into a 250-ml Erlenmeyer flask, add 2 to 4 drops of thorin indicator, and titrate to a pink endpoint using 0.0100 N barium perchlorate. Repeat the titration with a second aliquot of sample and average the titration values. Replicate titrations must agree within 1 percent or 0.2 ml, whichever is greater.

4.3.2 Container No. 2. Thoroughly mix the solution in the container holding the contents of the second and third impingers. Pipette a 10-ml aliquot of sample into a 250-ml Erlenmeyer flask. Add 40 ml of isopropanol, 2 to 4 drops of thorin indicator, and titrate to a pink endpoint using 0.0100 N barium perchlorate. Repeat the titration with a second aliquot of sample and average the titration values. Replicate titrations must agree within 1 percent or 0.2 ml, whichever is greater. [87]

4.3.3 Blanks. Prepare blanks by adding 2 to 4 drops of thorin indicator to 100 ml of 80 percent isopropanol. Titrate the blanks in the same manner as the samples.

5. Calibration

5.1 Calibrate equipment using the procedures specified in the following sections of Method 5: Section 5.3 (metering system); Section 5.5 (temperature gauges); Section 5.7 (barometer). Note that the recommended leak-check of the metering system, described in Section 5.6 of Method 5, also applies to this method.

5.2 Standardize the barium perchlorate solution with 25 ml of standard sulfuric acid, to which 100 ml of 100 percent isopropanol has been added.

6. Calculations

Note.—Carry out calculations retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

6.1 Nomenclature.

A_n = Cross-sectional area of nozzle, m² (ft²).

B_{ws} = Water vapor in the gas stream, proportion by volume.

$C_{H_2SO_4}$ = Sulfuric acid (including SO_3) concentration, g/dscm (lb/dscf). [87]

C_{SO_2} = Sulfur dioxide concentration, g/dscm (lb/dscf). [87]

I = Percent of isokinetic sampling.

N = Normality of barium perchlorate titrant, g equivalents/liter.

P_{bar} = Barometric pressure at the sampling site, mm Hg (in. Hg). [87]

P_s = Absolute stack gas pressure, mm Hg (in. Hg).

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg). [87]

T_m = Average absolute dry gas meter temperature (see Figure 8-2), °K (° R).

T_s = Average absolute stack gas temperature (see Figure 8-2), ° K (° R).

T_{std} = Standard absolute temperature, 293° K (528° R). [87]

V_a = Volume of sample aliquot titrated, 100 ml for H_2SO_4 and 10 ml for SO_2.

V_{lc} = Total volume of liquid collected in impingers and silica gel, ml.

V_m = Volume of gas sample as measured by dry gas meter, dcm (dcf).

$V_{m(std)}$ = Volume of gas sample measured by the dry gas meter corrected to standard conditions, dscm (dscf). [87]

v_s = Average stack gas velocity, calculated by Method 2, Equation 2-9, using data obtained from Method 8, m/sec (ft/sec).

V_{soln} = Total volume of solution in which the sulfuric acid or sulfur dioxide sample is contained, 250 ml or 1,000 ml, respectively. [87]

V_t = Volume of barium perchlorate titrant used for the sample, ml.

V_{tb} = Volume of barium perchlorate titrant used for the blank, ml.

Y = Dry gas meter calibration factor.

ΔH = Average pressure drop across orifice meter, mm (in.) H_2O.

θ = Total sampling time, min.

13.6 = Specific gravity of mercury.

60 = sec/min.

100 = Conversion to percent.

6.2 Average dry gas meter temperature and average orifice pressure drop. See data sheet (Figure 8-2).

6.3 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20° C and 760 mm Hg or 68° F and 29.92 in. Hg) by using Equation 8-1.

$$V_{m(std)} = V_m Y \left(\frac{T_{std}}{T_m}\right) \frac{P_{bar} + \left(\frac{\Delta H}{13.6}\right)}{P_{std}}$$

$$= K_1 V_m Y \frac{P_{bar} + (\Delta H/13.6)}{T_m}$$

Equation 8-1

where:

K_1 = 0.3858 °K/mm Hg for metric units.
= 17.64 °R/in. Hg for English units.

NOTE.—If the leak rate observed during any mandatory leak-checks exceeds the specified acceptable rate, the tester shall either correct the value of V_m in Equation 8-1 (as described in Section 6.3 of Method 5), or shall invalidate the test run.

6.4 Volume of Water Vapor and Moisture Content. Calculate the volume of water vapor using Equation 5-2 of Method 5; the weight of water collected in the impingers and silica gel can be directly converted to milliliters (the specific gravity of water is 1 g/ml). Calculate the moisture content of the stack gas, using Equation 5-3 of Method 5. The "Note" in Section 6.5 of Method 5 also applies to this method. Note that if the effluent gas stream can be considered dry, the volume of water vapor and moisture content need not be calculated.

6.5 Sulfuric acid mist (including SO_3) concentration.

$$C_{H_2SO_4} = K_2 \frac{N(V_t - V_{tb})\left(\frac{V_{soln}}{V_a}\right)}{V_{m(std)}}$$

Equation 8-2

where:

K_2 = 0.04904 g/milliequivalent for metric units.
= 1.081×10⁻⁴ lb/meq for English units.

6.6 Sulfur dioxide concentration.

$$C_{SO_2} = K_3 \frac{N(V_t - V_{tb})\left(\frac{V_{soln}}{V_a}\right)}{V_{m(std)}}$$

Equation 8-3

where:

K_3 = 0.03203 g/meq for metric units.
= 7.061×10⁻⁴ lb/meq for English units.

6.7 Isokinetic Variation.

6.7.1 Calculation from raw data.

$$I = \frac{100\, T_s [K_4 V_{lc} + (V_m Y/T_m) P_{bar} + \Delta H/13.6)]}{60\, \theta\, V_s P_s A_n}$$

Equation 8-4 [87]

where:

K_4 = 0.003464 mm Hg-m³/ml-°K for metric units.
= 0.002676 in. Hg-ft³/ml-°R for English units.

6.7.2 Calculation from intermediate values.

$$I = \frac{T_s V_{m(std)} P_{std}\, 100}{T_{std} v_s \theta A_n P_s\, 60\,(1 - B_{ws})}$$

$$= K_5 \frac{T_s V_{m(std)}}{P_s v_s A_n \theta (1 - B_{ws})}$$

Equation 8-5

where:

K_5 = 4.320 for metric units.
= 0.00450 for English units.

6.8 Acceptable Results. If 90 percent ≤I ≤110 percent, the results are acceptable. If the results are low in comparison to the standards and I is beyond the acceptable range, the Administrator may opt to accept the results. Use Citation 4 in the Bibliography of Method 5 to make judgments. Otherwise, reject the results and repeat the test.

7. Bibliography

1. Atmospheric Emissions from Sulfuric Acid Manufacturing Processes. U.S. DHEW, PHS, Division of Air Pollution. Public Health Service Publication No. 999-AP-13. Cincinnati, Ohio. 1965.

2. Corbett, P. F. The Determination of SO_2 and SO_3 in Flue Gases. Journal of the Institute of Fuel. 24:237-243. 1961.

3. Martin, Robert M. Construction Details of Isokinetic Source Sampling Equipment. Environmental Protection Agency. Research Triangle Park, N.C. Air Pollution Control Office Publication No. APTD-0581. April, 1971.

4. Patton, W. F. and J. A. Brink, Jr. New Equipment and Techniques for Sampling Chemical Process Gases. Journal of Air Pollution Control Association. 13:162. 1963.

5. Rom, J. J. Maintenance, Calibration, and Operation of Isokinetic Source-Sampling Equipment. Office of Air Programs, Environmental Protection Agency. Research Triangle Park, N.C. APTD-0576. March, 1972.

6. Hamil, H. F. and D. E. Camann. Collaborative Study of Method for Determination of Sulfur Dioxide Emissions from Stationary Sources (Fossil Fuel-Fired Steam Generators). Environmental Protection Agency. Research Triangle Park, N.C. EPA-650/4-74-024. December, 1973.

7. Annual Book of ASTM Standards. Part 31; Water, Atmospheric Analysis. pp. 40-42. American Society for Testing and Materials. Philadelphia, Pa. 1974.

METHOD 9—VISUAL DETERMINATION OF THE OPACITY OF EMISSIONS FROM STATIONARY SOURCES [10]

Many stationary sources discharge visible emissions into the atmosphere; these emissions are usually in the shape of a plume. This method involves the determination of plume opacity by qualified observers. The method includes procedures for the training and certification of observers, and procedures to be used in the field for determination of plume opacity. The appearance of a plume as viewed by an observer depends upon a number of variables, some of which may be controllable and some of which may not be controllable in the field. Variables which can be controlled to an extent to which they no longer exert a significant influence upon plume appearance include: Angle of the observer with respect to the plume; angle of the observer with respect to the sun; point of observation of attached and detached steam plume; and angle of the observer with respect to a plume emitted from a rectangular stack with a large length to width ratio. The method includes specific criteria applicable to these variables.

Other variables which may not be controllable in the field are luminescence and color contrast between the plume and the background against which the plume is viewed. These variables exert an influence upon the appearance of a plume as viewed by an observer, and can affect the ability of the observer to accurately assign opacity values to the observed plume. Studies of the theory of plume opacity and field studies have demonstrated that a plume is most visible and presents the greatest apparent opacity when *viewed against a contrasting background. It* follows from this, and is confirmed by field trials, that the opacity of a plume, viewed under conditions where a contrasting background is present can be assigned with the greatest degree of accuracy. However, the potential for a positive error is also the greatest when a plume is viewed under such contrasting conditions. Under conditions presenting a less contrasting background, the apparent opacity of a plume is less and approaches zero as the color and luminescence contrast decrease toward zero. As a result, significant negative bias and negative errors can be made when a plume is viewed under less contrasting conditions. A negative bias decreases rather than increases the possibility that a plant operator will be cited for a violation of opacity standards due to observer error.

Studies have been undertaken to determine the magnitude of positive errors which can be made by qualified observers while reading plumes under contrasting conditions and using the procedures set forth in this method. The results of these studies (field trials) which involve a total of 769 sets of 25 readings each are as follows:

(1) For black plumes (133 sets at a smoke generator), 100 percent of the sets were read with a positive error[1] of less than 7.5 percent opacity; 99 percent were read with a positive error of less than 5 percent opacity.

(2) For white plumes (170 sets at a smoke generator, 168 sets at a coal-fired power plant, 298 sets at a sulfuric acid plant), 99 percent of the sets were read with a positive error of less than 7.5 percent opacity; 95 percent were read with a positive error of less than 5 percent opacity.

The positive observational error associated with an average of twenty-five readings is therefore established. The accuracy of the method must be taken into account when determining possible violations of applicable opacity standards.

[1] For a set, positive error=average opacity determined by observers' 25 observations—average opacity determined from transmissometer's 25 recordings.

1. *Principle and applicability.*

1.1 Principle. The opacity of emissions from stationary sources is determined visually by a qualified observer.

1.2 Applicability. This method is applicable for the determination of the opacity of emissions from stationary sources pursuant to § 60.11(b) and for qualifying observers for visually determining opacity of emissions.

2. *Procedures.* The observer qualified in accordance with paragraph 3 of this method shall use the following procedures for visually determining the opacity of emissions:

2.1 Position. The qualified observer shall stand at a distance sufficient to provide a clear view of the emissions with the sun oriented in the 140° sector to his back. Consistent with maintaining the above requirement, the observer shall, as much as possible, make his observations from a position such that his line of vision is approximately perpendicular to the plume direction, and when observing opacity of emissions from rectangular outlets (e.g. roof monitors, open baghouses, noncircular stacks), approximately perpendicular to the longer axis of the outlet. The observer's line of sight should not include more than one plume at a time when multiple stacks are involved, and in any case the observer should make his observations with his line of sight perpendicular to the longer axis of such a set of multiple stacks (e.g. stub stacks on baghouses).

2.2 Field records. The observer shall record the name of the plant, emission location, type facility, observer's name and affiliation, and the date on a field data sheet (Figure 9–1). The time, estimated distance to the emission location, approximate wind direction, estimated wind speed, description of the sky condition (presence and color of clouds), and plume background are recorded on a field data sheet at the time opacity readings are initiated and completed.

2.3 Observations. Opacity observations shall be made at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. The observer shall not look continuously at the plume, but instead shall observe the plume momentarily at 15-second intervals.

2.3.1 Attached steam plumes. When condensed water vapor is present within the plume as it emerges from the emission outlet, opacity observations shall be made beyond the point in the plume at which condensed water vapor is no longer visible. The observer shall record the approximate distance from the emission outlet to the point in the plume at which the observations are made.

2.3.2 Detached steam plume. When water vapor in the plume condenses and becomes visible at a distinct distance from the emission outlet, the opacity of emissions should be evaluated at the emission outlet prior to the condensation of water vapor and the formation of the steam plume.

2.4 Recording observations. Opacity observations shall be recorded to the nearest 5 percent at 15-second intervals on an observational record sheet. (See Figure 9–2 for an example.) A minimum of 24 observations shall be recorded. Each momentary observation recorded shall be deemed to represent the average opacity of emissions for a 15-second period.

2.5 Data Reduction. Opacity shall be determined as an average of 24 consecutive observations recorded at 15-second intervals. Divide the observations recorded on the record sheet into sets of 24 consecutive observations. A set is composed of any 24 consecutive observations. Sets need not be consecutive in time and in no case shall two sets overlap. For each set of 24 observations, calculate the average by summing the opacity of the 24 observations and dividing this sum by 24. If an applicable standard specifies an averaging time requiring more than 24 observations, calculate the average for all observations made during the specified time period. Record the average opacity on a record sheet. (See Figure 9–1 for an example.)

3. *Qualifications and testing.*

3.1 Certification requirements. To receive certification as a qualified observer, a candidate must be tested and demonstrate the ability to assign opacity readings in 5 percent increments to 25 different black plumes and 25 different white plumes, with an error not to exceed 15 percent opacity on any one reading and an average error not to exceed 7.5 percent opacity in each category. Candidates shall be tested according to the procedures described in paragraph 3.2. Smoke generators used pursuant to paragraph 3.2 shall be equipped with a smoke meter which meets the requirements of paragraph 3.3.

The certification shall be valid for a period of 6 months, at which time the qualification procedure must be repeated by any observer in order to retain certification.

3.2 Certification procedure. The certification test consists of showing the candidate a complete run of 50 plumes—25 black plumes and 25 white plumes—generated by a smoke generator. Plumes within each set of 25 black and 25 white runs shall be presented in random order. The candidate assigns an opacity value to each plume and records his observation on a suitable form. At the completion of each run of 50 readings, the score of the candidate is determined. If a candidate fails to qualify, the complete run of 50 readings must be repeated in any retest. The smoke test may be administered as part of a smoke school or training program, and may be preceded by training or familiarization runs of the smoke generator during which candidates are shown black and white plumes of known opacity.

3.3 Smoke generator specifications. Any smoke generator used for the purposes of paragraph 3.2 shall be equipped with a smoke meter installed to measure opacity across the diameter of the smoke generator stack. The smoke meter output shall display instack opacity based upon a pathlength equal to the stack exit diameter, on a full 0 to 100 percent chart recorder scale. The smoke meter optical design and performance shall meet the specifications shown in Table 9–1. The smoke meter shall be calibrated as prescribed in paragraph 3.3.1 prior to the conduct of each smoke reading test. At the completion of each test, the zero and span drift shall be checked and if the drift exceeds ±1 percent opacity, the condition shall be corrected prior to conducting any subsequent test runs. The smoke meter shall be demonstrated, at the time of installation, to meet the specifications listed in Table 9–1. This demonstration shall be repeated following any subsequent repair or replacement of the photocell or associated electronic circuitry including the chart recorder or output meter, or every 6 months, whichever occurs first.

3.3.1 Calibration. The smoke meter is calibrated after allowing a minimum of 30 minutes warmup by alternately producing simulated opacity of 0 percent and 100 percent. When stable response at 0 percent or 100 percent is noted, the smoke meter is adjusted to produce an output of 0 percent or 100 percent, as appropriate. This calibration shall be repeated until stable 0 percent and 100 percent readings are produced without adjustment. Simulated 0 percent and 100 percent opacity values may be produced by alternately switching the power to the light source on and off while the smoke generator is not producing smoke.

TABLE 9-1—SMOKE METER DESIGN AND PERFORMANCE SPECIFICATIONS

Parameter:	*Specification*
a. Light source	Incandescent lamp operated at nominal rated voltage.
b. Spectral response of photocell.	Photopic (daylight spectral response of the human eye—reference 4.3).
c. Angle of view	15° maximum total angle.
d. Angle of projection.	15° maximum total angle.
e. Calibration error.	±3% opacity, maximum.
f. Zero and span drift.	±1% opacity, 30 minutes.
g. Response time	≤5 seconds.

3.3.2 Smoke meter evaluation. The smoke meter design and performance are to be evaluated as follows:

3.3.2.1 Light source. Verify from manufacturer's data and from voltage measurements made at the lamp, as installed, that the lamp is operated within ±5 percent of the nominal rated voltage.

3.3.2.2 Spectral response of photocell. Verify from manufacturer's data that the photocell has a photopic response; i.e., the spectral sensitivity of the cell shall closely approximate the standard spectral-luminosity curve for photopic vision which is referenced in (b) of Table 9-1.

3.3.2.3 Angle of view. Check construction geometry to ensure that the total angle of view of the smoke plume, as seen by the photocell, does not exceed 15°. The total angle of view may be calculated from: $\theta = 2 \tan^{-1} d/2L$, where θ = total angle of view; d = the sum of the photocell diameter + the diameter of the limiting aperture; and L = the distance from the photocell to the limiting aperture. The limiting aperture is the point in the path between the photocell and the smoke plume where the angle of view is most restricted. In smoke generator smoke meters this is normally an orifice plate.

3.3.2.4 Angle of projection. Check construction geometry to ensure that the total angle of projection of the lamp on the smoke plume does not exceed 15°. The total angle of projection may be calculated from: $\theta = 2 \tan^{-1} d/2L$, where θ = total angle of projection; d = the sum of the length of the lamp filament + the diameter of the limiting aperture; and L = the distance from the lamp to the limiting aperture.

3.3.2.5 Calibration error. Using neutral-density filters of known opacity, check the error between the actual response and the theoretical linear response of the smoke meter. This check is accomplished by first calibrating the smoke meter according to 3.3.1 and then inserting a series of three neutral-density filters of nominal opacity of 20, 50, and 75 percent in the smoke meter pathlength. Filters calibarted within ±2 percent shall be used. Care should be taken when inserting the filters to prevent stray light from affecting the meter. Make a total of five nonconsecutive readings for each filter. The maximum error on any one reading shall be 3 percent opacity.

3.3.2.6 Zero and span drift. Determine the zero and span drift by calibrating and operating the smoke generator in a normal manner over a 1-hour period. The drift is measured by checking the zero and span at the end of this period.

3.3.2.7 Response time. Determine the response time by producng the series of five simulated 0 percent and 100 percent opacity values and observing the time required to reach stable response. Opacity values of 0 percent and 100 percent may be simulated by alternately switching the power to the light source off and on while the smoke generator is not operating.

4. *References.*

4.1 Air Pollution Control District Rules and Regulations, Los Angeles County Air Pollution Control District, Regulation IV, Prohibitions, Rule 50.

4.2 Weisburd, Melvin I., Field Operations and Enforcement Manual for Air, U.S. Environmental Protection Agency, Research Triangle Park, N.C., APTD-1100, August 1972, pp. 4.1-4.36.

4.3 Condon, E. U., and Odishaw, H., Handbook of Physics, McGraw-Hill Co., N.Y., N.Y., 1958, Table 3.1, p. 6-52.

FIGURE 9-1
RECORD OF VISUAL DETERMINATION OF OPACITY PAGE___of___

COMPANY_____
LOCATION_____
TEST NUMBER_____
DATE_____
TYPE FACILITY_____
CONTROL DEVICE_____

HOURS OF OBSERVATION_____
OBSERVER_____
OBSERVER CERTIFICATION DATE_____
OBSERVER AFFILIATION_____
POINT OF EMISSIONS_____
HEIGHT OF DISCHARGE POINT_____

	Initial			Final
CLOCK TIME				
OBSERVER LOCATION Distance to Discharge				
Direction from Discharge				
Height of Observation Point				
BACKGROUND DESCRIPTION				
WEATHER CONDITIONS Wind Direction				
Wind Speed				
Ambient Temperature				
SKY CONDITIONS (clear, overcast, % clouds, etc.)				
PLUME DESCRIPTION Color				
Distance Visible				
OTHER INFORMATION				

SUMMARY OF AVERAGE OPACITY

Set Number	Time	Opacity	
	Start--End	Sum	Average

Readings ranged from ____ to ____ % opacity

The source was/was not in compliance with ____ at the time evaluation was made.

FIGURE 9-2 OBSERVATION RECORD PAGE ___ OF ___

COMPANY _____ OBSERVER _____
LOCATION _____ TYPE FACILITY _____
TEST NUMBER _____ POINT OF EMISSIONS _____
DATE _____

Hr.	Min.	Seconds 0	15	30	45	STEAM PLUME (check if applicable) Attached	Detached	COMMENTS
	0							
	1							
	2							
	3							
	4							
	5							
	6							
	7							
	8							
	9							
	10							
	11							
	12							
	13							
	14							
	15							
	16							
	17							
	18							
	19							
	20							
	21							
	22							
	23							
	24							
	25							
	26							
	27							
	28							
	29							

FIGURE 9-2 OBSERVATION RECORD (Continued) PAGE ___ OF ___

COMPANY _____ OBSERVER _____
LOCATION _____ TYPE FACILITY _____
TEST NUMBER _____ POINT OF EMISSIONS _____
DATE _____

Hr.	Min.	Seconds 0	15	30	45	STEAM PLUME (check if applicable) Attached	Detached	COMMENTS
	30							
	31							
	32							
	33							
	34							
	35							
	36							
	37							
	38							
	39							
	40							
	41							
	42							
	43							
	44							
	45							
	46							
	47							
	48							
	49							
	50							
	51							
	52							
	53							
	54							
	55							
	56							
	57							
	58							
	59							

[FR Doc.74-26160 Filed 11-11-74;8:45 am]

METHOD 10—DETERMINATION OF CARBON MONOXIDE EMISSIONS FROM STATIONARY SOURCES [5]

1. *Principle and Applicability.*

1.1 *Principle.* An integrated or continuous gas sample is extracted from a sampling point and analyzed for carbon monoxide (CO) content using a Luft-type nondispersive infrared analyzer (NDIR) or equivalent.

1.2 *Applicability.* This method is applicable for the determination of carbon monoxide emissions from stationary sources only when specified by the test procedures for determining compliance with new source performance standards. The test procedure will indicate whether a continuous or an integrated sample is to be used.

2. *Range and sensitivity.*

2.1 *Range.* 0 to 1,000 ppm.

2.2 *Sensitivity.* Minimum detectable concentration is 20 ppm for a 0 to 1,000 ppm span.

3. *Interferences.* Any substance having a strong absorption of infrared energy will interfere to some extent. For example, discrimination ratios for water (H_2O) and carbon dioxide (CO_2) are 3.5 percent H_2O per 7 ppm CO and 10 percent CO_2 per 10 ppm CO, respectively, for devices measuring in the 1,500 to 3,000 ppm range. For devices measuring in the 0 to 100 ppm range, interference ratios can be as high as 3.5 percent H_2O per 25 ppm CO and 10 percent CO_2 per 50 ppm CO. The use of silica gel and ascarite traps will alleviate the major interference problems. The measured gas volume must be corrected if these traps are used.

4. *Precision and accuracy.*

4.1 *Precision.* The precision of most NDIR analyzers is approximately ±2 percent of span.

4.2 *Accuracy.* The accuracy of most NDIR analyzers is approximately ±5 percent of span after calibration.

5. *Apparatus.*

5.1 *Continuous sample* (Figure 10–1).

5.1.1 *Probe.* Stainless steel or sheathed Pyrex [1] glass, equipped with a filter to remove particulate matter.

5.1.2 *Air-cooled condenser or equivalent.* To remove any excess moisture.

5.2 *Integrated sample* (Figure 10–2).

5.2.1 *Probe.* Stainless steel or sheathed Pyrex glass, equipped with a filter to remove particulate matter.

5.2.2 *Air-cooled condenser or equivalent.* To remove any excess moisture.

5.2.3 *Valve.* Needle valve, or equivalent, to adjust flow rate.

5.2.4 *Pump.* Leak-free diaphragm type, or equivalent, to transport gas.

5.2.5 *Rate meter.* Rotameter, or equivalent, to measure a flow range from 0 to 1.0 liter per min. (0.035 cfm).

5.2.6 *Flexible bag.* Tedlar, or equivalent, with a capacity of 60 to 90 liters (2 to 3 ft^3). Leak-test the bag in the laboratory before using by evacuating bag with a pump followed by a dry gas meter. When evacuation is complete, there should be no flow through the meter.

5.2.7 *Pitot tube.* Type S, or equivalent, attached to the probe so that the sampling rate can be regulated proportional to the stack gas velocity when velocity is varying with the time or a sample traverse is conducted.

5.3 *Analysis* (Figure 10–3).

[1] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

TABLE 10–1.—*Field data*

Location _____ Comments:
Test _____
Date _____
Operator _____

Clock time	*Rotameter setting, liters per minute (cubic feet per minute)*

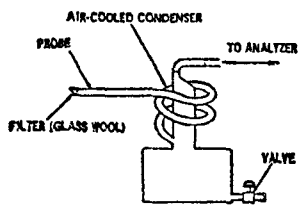


Figure 10-1. Continuous sampling train.

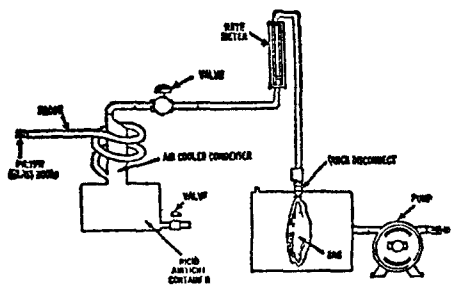


Figure 10-2. Integrated gas-sampling train.

5.3.1 *Carbon monoxide analyzer.* Nondispersive infrared spectrometer, or equivalent. This instrument should be demonstrated, preferably by the manufacturer, to meet or exceed manufacturer's specifications and those described in this method.

5.3.2 *Drying tube.* To contain approximately 200 g of silica gel.

5.3.3 *Calibration gas.* Refer to paragraph 6.1.

5.3.4 *Filter.* As recommended by NDIR manufacturer.

5.3.5 CO_2 *removal tube.* To contain approximately 500 g of ascarite.

5.3.6 *Ice water bath.* For ascarite and silica gel tubes.

5.3.7 *Valve.* Needle valve, or equivalent, to adjust flow rate

5.3.8 *Rate meter.* Rotameter or equivalent to measure gas flow rate of 0 to 1.0 liter per min. (0.035 cfm) through NDIR.

5.3.9 *Recorder (optional).* To provide permanent record of NDIR readings.

6. *Reagents.*

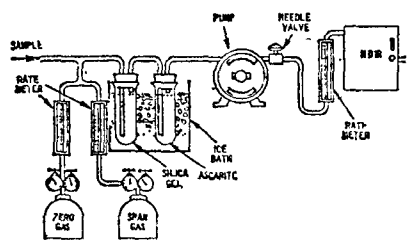


Figure 10-3. Analytical equipment.

6.1 *Calibration gases.* Known concentration of CO in nitrogen (N_2) for instrument span, prepurified grade of N_2 for zero, and two additional concentrations corresponding approximately to 60 percent and 30 percent span. The span concentration shall not exceed 1.5 times the applicable source performance standard. The calibration gases shall be certified by the manufacturer to be within ±2 percent of the specified concentration.

6.2 *Silica gel.* Indicating type, 6 to 16 mesh, dried at 175° C (347° F) for 2 hours.

6.3 *Ascarite.* Commercially available.

7. *Procedure.*

7.1 *Sampling.*

7.1.1 *Continuous sampling.* Set up the equipment as shown in Figure 10–1 making sure all connections are leak free. Place the probe in the stack at a sampling point and purge the sampling line. Connect the analyzer and begin drawing sample into the analyzer. Allow 5 minutes for the system to stabilize, then record the analyzer reading as required by the test procedure. (See ¶ 7.2 and 8). CO_2 content of the gas may be determined by using the Method 3 integrated sample procedure (36 FR 24886), or by weighing the ascarite CO_2 removal tube and computing CO_2 concentration from the gas volume sampled and the weight gain of the tube.

7.1.2 *Integrated sampling.* Evacuate the flexible bag. Set up the equipment as shown in Figure 10–2 with the bag disconnected. Place the probe in the stack and purge the sampling line. Connect the bag, making sure that all connections are leak free. Sample at a rate proportional to the stack velocity. CO_2 content of the gas may be determined by using the Method 3 integrated sample procedures (36 FR 24886), or by weighing the ascarite CO_2 removal tube and computing CO_2 concentration from the gas volume sampled and the weight gain of the tube.

7.2 *CO Analysis.* Assemble the apparatus as shown in Figure 10–3, calibrate the instrument, and perform other required operations as described in paragraph 8. Purge analyzer with N_2 prior to introduction of each sample. Direct the sample stream through the instrument for the test period, recording the readings. Check the zero and span again after the test to assure that any drift or malfunction is detected. Record the sample data on Table 10–1.

8. *Calibration.* Assemble the apparatus according to Figure 10–3. Generally an instrument requires a warm-up period before stability is obtained. Follow the manufacturer's instructions for specific procedure. Allow a minimum time of one hour for warm-up. During this time check the sample conditioning apparatus, i.e., filter, condenser, drying tube, and CO_2 removal tube, to ensure that each component is in good operating condition. Zero and calibrate the instrument according to the manufacturer's procedures using, respectively, nitrogen and the calibration gases.

9. *Calculation—Concentration of carbon monoxide.* Calculate the concentration of carbon monoxide in the stack using equation 10–1.

$$C_{CO_{stack}} = C_{CO_{NDIR}}(1 - F_{CO_2}) \qquad \text{equation 10–1}$$

where:

$C_{CO_{stack}}$ = concentration of CO in stack, ppm by volume (dry basis).

$C_{CO_{NDIR}}$ = concentration of CO measured by NDIR analyzer, ppm by volume (dry basis). [6]

F_{CO_2} = volume fraction of CO_2 in sample, i.e., percent CO_2 from Orsat analysis divided by 100.

10. *Bibliography.*

10.1 McElroy, Frank, The Intertech NDIR–CO Analyzer, Presented at 11th Methods Conference on Air Pollution, University of California, Berkeley, Calif., April 1, 1970.

10.2 Jacobs, M. B., et al., Continuous Determination of Carbon Monoxide and Hydrocarbons in Air by a Modified Infrared Analyzer, J. Air Pollution Control Association, 9(2):110–114, August 1959.

10.3 MSA LIRA Infrared Gas and Liquid Analyzer Instruction Book, Mine Safety Appliances Co., Technical Products Division, Pittsburgh, Pa.

10.4 Models 215A, 315A, and 415A Infrared Analyzers, Beckman Instruments, Inc., Beckman Instructions 1635–B, Fullerton, Calif., October 1967.

10.5 Continuous CO Monitoring System, Model A5611, Intertech Corp., Princeton, N.J.

10.6 UNOR Infrared Gas Analyzers, Bendix Corp., Ronceverte, West Virginia.

ADDENDA

A. Performance Specifications for NDIR Carbon Monoxide Analyzers.

Range (minimum)	0–1000ppm.
Output (minimum)	0–10mV.
Minimum detectable sensitivity	20 ppm.
Rise time, 90 percent (maximum)	30 seconds.
Fall time, 90 percent (maximum)	30 seconds.
Zero drift (maximum)	10% in 8 hours.
Span drift (maximum)	10% in 8 hours.
Precision (minimum)	± 2% of full scale.
Noise (maximum)	± 1% of full scale.
Linearity (maximum deviation)	2% of full scale.
Interference rejection ratio	CO_2—1000 to 1, H_2O—500 to 1.

B. *Definitions of Performance Specifications.*

Range—The minimum and maximum measurement limits.

Output—Electrical signal which is proportional to the measurement; intended for connection to readout or data processing devices. Usually expressed as millivolts or milliamps full scale at a given impedance.

Full scale—The maximum measuring limit for a given range.

Minimum detectable sensitivity—The smallest amount of input concentration that can be detected as the concentration approaches zero.

Accuracy—The degree of agreement between a measured value and the true value; usually expressed as ± percent of full scale.

Time to 90 percent response—The time interval from a step change in the input concentration at the instrument inlet to a reading of 90 percent of the ultimate recorded concentration.

Rise Time (90 percent)—The interval between initial response time and time to 90 percent response after a step increase in the inlet concentration.

Fall Time (90 percent)—The interval between initial response time and time to 90 percent response after a step decrease in the inlet concentration.

Zero Drift—The change in instrument output over a stated time period, usually 24 hours, of unadjusted continuous operation when the input concentration is zero; usually expressed as percent full scale.

Span Drift—The change in instrument output over a stated time period, usually 24 hours, of unadjusted continuous operation when the input concentration is a stated upscale value; usually expressed as percent full scale.

Precision—The degree of agreement between repeated measurements of the same concentration, expressed as the average deviation of the single results from the mean.

Noise—Spontaneous deviations from a mean output not caused by input concentration changes.

Linearity—The maximum deviation between an actual instrument reading and the reading predicted by a straight line drawn between upper and lower calibration points.

METHOD 11—DETERMINATION OF HYDROGEN SULFIDE CONTENT OF FUEL GAS STREAMS IN PETROLEUM REFINERIES[79]

1. *Principle and applicability.* 1.1 *Principle.* Hydrogen sulfide (H_2S) is collected from a source in a series of midget impingers and absorbed in pH 3.0 cadmium sulfate ($CdSO_4$) solution to form cadmium sulfide (CdS). The latter compound is then measured iodometrically. An impinger containing hydrogen peroxide is included to remove SO_2 as an interfering species. This method is a revision of the H_2S method originally published in the FEDERAL REGISTER, Volume 39, No. 47, dated Friday, March 8, 1974.

1.2 *Applicability.* This method is applicable for the determination of the hydrogen sulfide content of fuel gas streams at petroleum refineries.

2. *Range and sensitivity.* The lower limit of detection is approximately 8 mg/m³ (6 ppm). The maximum of the range is 740 mg/m³ (520 ppm).

3. *Interferences.* Any compound that reduces iodine or oxidizes iodide ion will interfere in this procedure, provide it is collected in the cadmium sulfate impingers. Sulfur dioxide in concentrations of up to 2,600 mg/m³ is eliminated by the hydrogen peroxide solution. Thiols precipitate with hydrogen sulfide. In the absence of H_2S, only co-traces of thiols are collected. When methane- and ethane-thiols at a total level of 300 mg/m³ are present in addition to H_2S, the results vary from 2 percent low at an H_2S concentration of 400 mg/m³ to 14 percent high at an H_2S concentration of 100 mg/m³. Carbon oxysulfide at a concentration of 20 percent does not interfere. Certain carbonyl-containing compounds react with iodine and produce recurring end points. However, acetaldehyde and acetone at concentrations of 1 and 3 percent, respectively, do not interfere.

Entrained hydrogen peroxide produces a negative interference equivalent to 100 percent of that of an equimolar quantity of hydrogen sulfide. Avoid the ejection of hydrogen peroxide into the cadmium sulfate impingers.

4. *Precision and accuracy.* Collaborative testing has shown the within-laboratory coefficient of variation to be 2.2 percent and the overall coefficient of variation to be 5 percent. The method bias was shown to be —4.8 percent when only H_2S was present. In the presence of the interferences cited in section 3, the bias was positive at low H_2S concentrations and negative at higher concentrations. At 230 mg H_2S/m³, the level of the compliance standard, the bias was +2.7 percent. Thiols had no effect on the precision.

5. *Apparatus.*

5.1 Sampling apparatus.

5.1.1 Sampling line. Six to 7 mm (¼ in.) Teflon[1] tubing to connect the sampling train to the sampling valve.

5.1.2 Impingers. Five midget impingers, each with 30 ml capacity. The internal diameter of the impinger tip must be 1 mm ±0.05 mm. The impinger tip must be positioned 4 to 6 mm from the bottom of the impinger.

5.1.3 Glass or Teflon connecting tubing for the impingers.

5.1.4 Ice bath container. To maintain absorbing solution at a low temperature.

5.1.5 Drying tube. Tube packed with 6- to 16-mesh indicating-type silica gel, or equivalent, to dry the gas sample and protect the meter and pump. If the silica gel has been used previously, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to approval of the Administrator.

NOTE.—Do not use more than 30 g of silica gel. Silica gel absorbs gases such as propane from the fuel gas stream, and use of excessive amounts of silica gel could result in errors in the determination of sample volume.

5.1.6 Sampling valve. Needle valve or equivalent to adjust gas flow rate. Stainless steel or other corrosion-resistant material.

5.1.7 Volume meter. Dry gas meter, sufficiently accurate to measure the sample volume within 2 percent, calibrated at the selected flow rate (~1.0 liter/min) and conditions actually encountered during sampling. The meter shall be equipped with a temperature gauge (dial thermometer or equivalent) capable of measuring temperature to within 3° C (5.4° F). The gas meter should have a petcock, or equivalent, on the outlet connector which can be closed during the leak check. Gas volume for one revolution of the meter must not be more than 10 liters.

5.1.8 Flow meter. Rotameter or equivalent, to measure flow rates in the range from 0.5 to 2 liters/min (1 to 4 cfh).

5.1.9 Graduated cylinder, 25 ml size.

5.1.10 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby National Weather Service station, in which case, the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and the sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice-versa for elevation decrease.

5.1.11 U-tube manometer. 0-30 cm water column. For leak check procedure.

5.1.12 Rubber squeeze bulb. To pressurize train for leak check.

5.1.13 Tee, pinchclamp, and connecting tubing. For leak check.

5.1.14 Pump. Diaphragm pump, or equivalent. Insert a small surge tank between the pump and rate meter to eliminate the pulsation effect of the diaphragm pump on the rotameter. The pump is used for the air purge at the end of the sample run; the pump is not ordinarily used during sampling, because fuel gas streams are usually sufficiently pressurized to force sample gas through the train at the required flow rate. The pump need not be leak-free unless it is used for sampling.

5.1.15 Needle valve or critical orifice. To set air purge flow to 1 liter/min.

5.1.16 Tube packed with active carbon. To filter air during purge.

5.1.17 Volumetric flask. One 1,000 ml.

5.1.18 Volumetric pipette. One 15 ml.

5.1.19 Pressure-reduction regulator. Depending on the sampling stream pressure, a pressure-reduction regulator may be needed to reduce the pressure of the gas stream entering the Teflon sample line to a safe level.

5.1.20 Cold trap. If condensed water or amine is present in the sample stream, a corrosion-resistant cold trap shall be used immediately after the sample tap. The trap shall not be operated below 0° C (32° F) to avoid condensation of C_3 or C_4 hydrocarbons.

5.2 Sample recovery.

5.2.1 Sample container. Iodine flask, glass-stoppered: 500 ml size.

5.2.2 Pipette. 50 ml volumetric type.

5.2.3 Graduated cylinders. One each 25 and 250 ml.

5.2.4 Flasks. 125 ml, Erlenmeyer.

5.2.5 Wash bottle.

5.2.6 Volumetric flasks. Three 1,000 ml.

5.3 Analysis.

5.3.1 Flask. 500 ml glass-stoppered iodine flask.

5.3.2 Burette. 50 ml.

5.3.3 Flask. 125 ml, Erlenmeyer.

5.3.4 Pipettes, volumetric. One 25 ml; two each 50 and 100 ml.

5.3.5 Volumetric flasks. One 1,000 ml; two 500 ml.

5.3.6 Graduated cylinders. One each 10 and 100 ml.

6. *Reagents.* Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available. Otherwise, use best available grade.

6.1 Sampling.

6.1.1 Cadmium sulfate absorbing solution. Dissolve 41 g of $3CdSO_4 \cdot 8H_2O$ and 15 ml of 0.1 M sulfuric acid in a 1-liter volumetric flask that contains approximately ¾ liter of deionized distilled water. Dilute to volume with deionized water. Mix thoroughly. pH should be 3±0.1. Add 10 drops of Dow-Corning Antifoam B. Shake well before use. If Antifoam B is not used, the alternate acidified iodine extraction procedure (section 7.2.2) must be used.

6.1.2 Hydrogen peroxide, 3 percent. Dilute 30 percent hydrogen peroxide to 3 percent as needed. Prepare fresh daily.

6.1.3 Water. Deionized, distilled to conform to ASTM specifications D1193-72, Type 3. At the option of the analyst, the $KMnO_4$ test for oxidizable organic matter may be omitted when high concentrations of organic matter are not expected to be present.

6.2 Sample recovery.

6.2.1 Hydrochloric acid solution (HCl), 3M. Add 240 ml of concentrated HCl (specific gravity 1.19) to 500 ml of deionized, distilled water in a 1-liter volumetric flask. Dilute to 1 liter with deionized water. Mix thoroughly.

6.2.2 Iodine solution 0.1 N. Dissolve 24 g of potassium iodide (KI) in 30 ml of deionized, distilled water. Add 12.7 g of resublimed iodine (I_2) to the potassium iodide solution. Shake the mixture until the iodine is completely dissolved. If possible, let the solution stand overnight in the dark. Slowly dilute the solution to 1 liter with deionized, distilled water, with swirling. Filter the solution if it is cloudy. Store solution in a brown-glass reagent bottle.

6.2.3 Standard iodine solution, 0.01 N. Pipette 100.0 ml of the 0.1 N iodine solution into a 1-liter volumetric flask and dilute to volume with deionized, distilled water. Standardize daily as in section 8.1.1. This solution must be protected from light. Reagent bottles and flasks must be kept tightly stoppered.

6.3 Analysis.

6.3.1 Sodium thiosulfate solution, standard 0.1 N. Dissolve 24.8 g of sodium thiosulfate pentahydrate ($Na_2S_2O_3 \cdot 5H_2O$) or 15.8 g of anhydrous sodium thiosulfate ($Na_2S_2O_3$) in 1 liter of deionized, distilled water and add 0.01 g of anhydrous sodium carbonate (Na_2CO_3) and 0.4 ml of chloroform ($CHCl_3$) to stabilize. Mix thoroughly by shaking or by aerating with nitrogen for approximately 15 minutes and store in a glass-stoppered, reagent bottle. Standardize as in section 8.1.2.

6.3.2 Sodium thiosulfate solution, standard 0.01 N. Pipette 50.0 ml of the standard 0.1 N thiosulfate solution into a volumetric flask and dilute to 500 ml with distilled water.

[1] Mention of trade names of specific products does not constitute endorsement by the Environmental Protection Agency.

NOTE.—A 0.01 N phenylarsine oxide solution may be prepared instead of 0.01 N thiosulfate (see section 6.3.3).

6.3.3 Phenylarsine oxide solution, standard 0.01 N. Dissolve 1.80 g of phenylarsine oxide (C_6H_5AsO) in 150 ml of 0.3 N sodium hydroxide. After settling, decant 140 ml of this solution into 800 ml of distilled water. Bring the solution to pH 6-7 with 6N hydrochloric acid and dilute to 1 liter. Standardize as in section 8.1.3.

6.3.4 Starch indicator solution. Suspend 10 g of soluble starch in 100 ml of deionized, distilled water and add 15 g of potassium hydroxide (KOH) pellets. Stir until dissolved, dilute with 900 ml of deionized distilled water and let stand for 1 hour. Neutralize the alkali with concentrated hydrochloric acid, using an indicator paper similar to Alkacid test ribbon, then add 2 ml of glacial acetic acid as a preservative.

NOTE.—Test starch indicator solution for decomposition by titrating, with 0.01 N iodine solution, 4 ml of starch solution in 200 ml of distilled water that contains 1 g potassium iodide. If more than 4 drops of the 0.01 N iodine solution are required to obtain the blue color, a fresh solution must be prepared.

7. *Procedure.*

7.1 Sampling.

7.1.1 Assemble the sampling train as shown in figure 11-1, connecting the five midget impingers in series. Place 15 ml of 3 percent hydrogen peroxide solution in the first impinger. Leave the second impinger empty. Place 15 ml of the cadmium sulfate absorbing solution in the third, fourth, and fifth impingers. Place the impinger assembly in an ice bath container and place crushed ice around the impingers. Add more ice during the run, if needed.

7.1.2 Connect the rubber bulb and manometer to first impinger, as shown in figure 11-1. Close the petcock on the dry gas meter outlet. Pressurize the train to 25-cm water pressure with the bulb and close off tubing connected to rubber bulb. The train must hold a 25-cm water pressure with not more than a 1-cm drop in pressure in a 1-minute interval. Stopcock grease is acceptable for sealing ground glass joints.

NOTE.—This leak check procedure is optional at the beginning of the sample run, but is mandatory at the conclusion. Note also that if the pump is used for sampling, it is recommended (but not required) that the pump be leak-checked separately, using a method consistent with the leak-check procedure for diaphragm pumps outlined in section 4.1.2 of reference method 6, 40 CFR Part 60, Appendix A.

7.1.3 Purge the connecting line between the sampling valve and first impinger, by disconnecting the line from the first impinger, opening the sampling valve, and allowing process gas to flow through the line for a minute or two. Then, close the sampling valve and reconnect the line to the impinger train. Open the petcock on the dry gas meter outlet. Record the initial dry gas meter reading.

7.1.4 Open the sampling valve and then adjust the valve to obtain a rate of approximately 1 liter/min. Maintain a constant (±10 percent) flow rate during the test. Record the meter temperature.

7.1.5 Sample for at least 10 min. At the end of the sampling time, close the sampling valve and record the final volume and temperature readings. Conduct a leak check as described in Section 7.1.2 above.

7.1.6 Disconnect the impinger train from the sampling line. Connect the charcoal tube and the pump, as shown in figure 11-1. Purge the train (at a rate of 1 liter/min) with clean ambient air for 15 minutes to ensure that all H_2S is removed from the hydrogen peroxide. For sample recovery, cap the open ends and remove the impinger train to a clean area that is away from sources of heat. The area should be well lighted, but not exposed to direct sunlight.

7.2 Sample recovery.

7.2.1 Discard the contents of the hydrogen peroxide impinger. Carefully rinse the contents of the third, fourth, and fifth impingers into a 500 ml iodine flask.

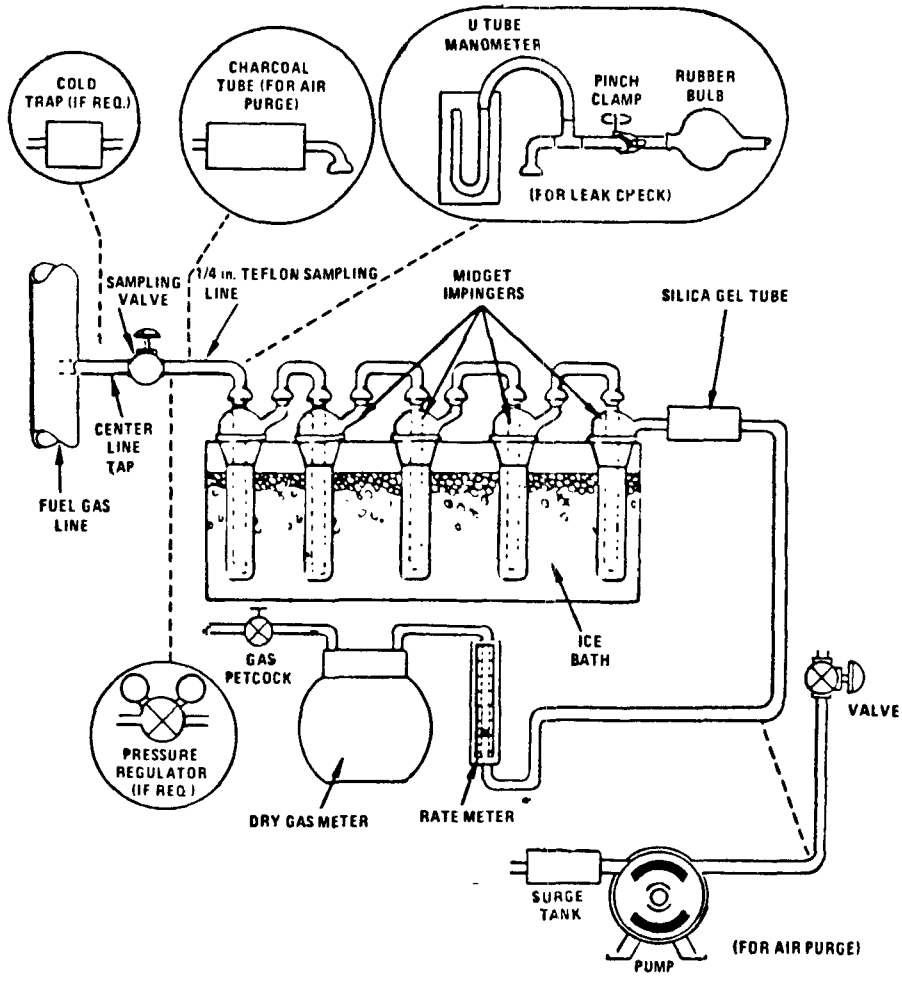


Figure 11-1. H_2S sampling train.

NOTE.—The impingers normally have only a thin film of cadmium sulfide remaining after a water rinse. If Antifoam B was not used or if significant quantities of yellow cadmium sulfide remain in the impingers, the alternate recovery procedure described below must be used.

7.2.2 Pipette exactly 50 ml of 0.01 N iodine solution into a 125 ml Erlenmeyer flask. Add 10 ml of 3 M HCl to the solution. Quantitatively rinse the acidified iodine into the iodine flask. Stopper the flask immediately and shake briefly.

7.2.2 (Alternate). Extract the remaining cadmium sulfide from the third, fourth, and fifth impingers using the acidified iodine solution. Immediately after pouring the acidified iodine into an impinger, stopper it and shake for a few moments, then transfer the liquid to the iodine flask. Do not transfer any rinse portion from one impinger to another; transfer it directly to the iodine flask. Once the acidified iodine solution has been poured into any glassware containing cadmium sulfide, the container must be tightly stoppered at all times except when adding more solution, and this must be done as quickly and carefully as possible. After adding any acidified iodine solution to the iodine flask, allow a few minutes for absorption of the H_2S before adding any further rinses. Repeat the iodine extraction until all cadmium sulfide is removed from the impingers. Extract that part of the connecting glassware that contains visible cadmium sulfide.

Quantitatively rinse all of the iodine from the impingers, connectors, and the beaker into the iodine flask using deionized, distilled water. Stopper the flask and shake briefly.

7.2.3 Allow the iodine flask to stand about 30 minutes in the dark for absorption of the H_2S into the iodine, then complete the titration analysis as in section 7.3.

NOTE.—Caution! Iodine evaporates from acidified iodine solutions. Samples to which acidified iodine have been added may not be stored, but must be analyzed in the time schedule stated in section 7.2.3.

7.2.4 Prepare a blank by adding 45 ml of cadmium sulfate absorbing solution to an iodine flask. Pipette exactly 50 ml of 0.01 N iodine solution into a 125-ml Erlenmeyer flask. Add 10 ml of 3 M HCl. Follow the same impinger extracting and quantitative rinsing procedure carried out in sample analysis. Stopper the flask, shake briefly, let stand 30 minutes in the dark, and titrate with the samples.

NOTE.—The blank must be handled by exactly the same procedure as that used for the samples.

7.3 Analysis.

NOTE.—Titration analyses should be conducted at the sample-cleanup area in order to prevent loss of iodine from the sample. Titration should never be made in direct sunlight.

7.3.1 Using 0.01 N sodium thiosulfate solution (or 0.01 N phenylarsine oxide, if applicable), rapidly titrate each sample in an iodine flask using gentle mixing, until solution is light yellow. Add 4 ml of starch indicator solution and continue titrating slowly until the blue color just disappears. Record V_{TT}, the volume of sodium thiosulfate solution used, or V_{AT}, the volume of phenylarsine oxide solution used (ml).

7.3.2 Titrate the blanks in the same manner as the samples. Run blanks each day until replicate values agree within 0.05 ml. Average the replicate titration values which agree within 0.05 ml.

8. *Calibration and standards.*

8.1 Standardizations.

8.1.1 Standardize the 0.01 N iodine solution daily as follows: Pipette 25 ml of the iodine solution into a 125 ml Erlenmeyer flask. Add 2 ml of 3 M HCl. Titrate rapidly with standard 0.01 N thiosulfate solution or with 0.01 N phenylarsine oxide until the solution is light yellow, using gentle mixing. Add four drops of starch indicator solution and continue titrating slowly until the blue color just disappears. Record V_T, the volume of thiosulfate solution used, or V_{AS}, the volume of phenylarsine oxide solution used (ml). Repeat until replicate values agree within 0.05 ml. Average the replicate titration values which agree within 0.05 ml and calculate the exact normality of the iodine solution using equation 9.3. Repeat the standardization daily.

8.1.2 Standardize the 0.1 N thiosulfate solution as follows: Oven-dry potassium dichromate ($K_2Cr_2O_7$) at 180 to 200° C (360 to 390° F). Weigh to the nearest milligram, 2 g of potassium dichromate. Transfer the dichromate to a 500 ml volumetric flask, dissolve in deionized, distilled water and dilute to exactly 500 ml. In a 500 ml iodine flask, dissolve approximately 3 g of potassium iodide (KI) in 45 ml of deionized, distilled water, then add 10 ml of 3 M hydrochloric acid solution. Pipette 50 ml of the dichromate solution into this mixture. Gently swirl the solution once and allow it to stand in the dark for 5 minutes. Dilute the solution with 100 to 200 ml of deionized distilled water, washing down the sides of the flask with part of the water. Titrate with 0.1 N thiosulfate until the solution is light yellow. Add 4 ml of starch indicator and continue titrating slowly to a green end point. Record V_s, the volume of thiosulfate solution used (ml). Repeat until replicate analyses agree within 0.05 ml. Calculate the normality using equation 9.1. Repeat the standardization each week, or after each test series, whichever time is shorter.

8.1.3 Standardize the 0.01 N Phenylarsine oxide (if applicable) as follows: oven dry potassium dichromate ($K_2Cr_2O_7$) at 180 to 200° C (360 to 390° F). Weigh to the nearest milligram, 2 g of the $K_2Cr_2O_7$; transfer the dichromate to a 500 ml volumetric flask, dissolve in deionized, distilled water, and dilute to exactly 500 ml. In a 500 ml iodine flask, dissolve approximately 0.3 g of potassium iodide (KI) in 45 ml of deionized, distilled water; add 10 ml of 3M hydrochloric acid. Pipette 5 ml of the $K_2Cr_2O_7$ solution into the iodine flask. Gently swirl the contents of the flask once and allow to stand in the dark for 5 minutes. Dilute the solution with 100 to 200 ml of deionized, distilled water, washing down the sides of the flask with part of the water. Titrate with 0.01 N phenylarsine oxide until the solution is light yellow. Add 4 ml of starch indicator and continue titrating slowly to a green end point. Record V_A, the volume of phenylarsine oxide used (ml). Repeat until replicate analyses agree within 0.05 ml. Calculate the normality using equation 9.2. Repeat the standardization each week or after each test series, whichever time is shorter.

8.2 Sampling train calibration. Calibrate the sampling train components as follows:

8.2.1 Dry gas meter.

8.2.1.1 Initial calibration. The dry gas meter shall be calibrated before its initial use in the field. Proceed as follows: First, assemble the following components in series: Drying tube, needle valve, pump, rotameter, and dry gas meter. Then, leak-check the system as follows: Place a vacuum gauge (at least 760 mm Hg) at the inlet to the drying tube and pull a vacuum of 250 mm (10 in.) Hg; plug or pinch off the outlet of the flow meter, and then turn off the pump. The vacuum shall remain stable for at least 30 seconds. Carefully release the vacuum gauge before releasing the flow meter end.

Next, calibrate the dry gas meter (at the sampling flow rate specified by the method) as follows: Connect an appropriately sized wet test meter (e.g., 1 liter per revolution) to the inlet of the drying tube. Make three independent calibration runs, using at least five revolutions of the dry gas meter per run. Calculate the calibration factor, Y (wet test meter calibration volume divided by the dry gas meter volume, both volumes adjusted to the same reference temperature and pressure), for each run, and average the results. If any Y value deviates by more than 2 percent from the average, the dry gas meter is unacceptable for use. Otherwise, use the average as the calibration factor for subsequent test runs.

8.2.1.2 Post-test calibration check. After each field test series, conduct a calibration check as in section 8.2.1.1. above, except for the following variations: (a) The leak check is not to be conducted, (b) three or more revolutions of the dry gas meter may be used, and (3) only two independent runs need be made. If the calibration factor does not deviate by more than 5 percent from the initial calibration factor (determined in section 8.2.1.1.), then the dry gas meter volumes obtained during the test series are acceptable. If the calibration factor deviates by more than 5 percent, recalibrate the dry gas meter as in section 8.2.1.1, and for the calculations, use the calibration factor (initial or recalibration) that yields the lower gas volume for each test run.

8.2.2 Thermometers. Calibrate against mercury-in-glass thermometers.

8.2.3 Rotameter. The rotameter need not be calibrated, but should be cleaned and maintained according to the manufacturer's instruction.

8.2.4 Barometer. Calibrate against a mercury barometer.

9. *Calculations.* Carry out calculations retaining at least one extra decimal figure beyond that of the acquired data. Round off results only after the final calculation.

9.1 Normality of the Standard (~0.1 N) Thiosulfate Solution.

$$N_s = 2.039 W/V_s$$

where:

W = Weight of $K_2Cr_2O_7$ used, g.
V_s = Volume of $Na_2S_2O_3$ solution used, ml.
N_s = Normality of standard thiosulfate solution, g-eq/liter.
2.039 = Conversion factor

(6 eq. I_2/mole $K_2Cr_2O_7$) (1,000 ml/liter)/= (294.2 g $K_2Cr_2O_7$/mole) (10 aliquot factor)

9.2 Normality of Standard Phenylarsine Oxide Solution (if applicable).

$$N_A = 0.2039\ W/V_A$$

where:

W = Weight of $K_2Cr_2O_7$ used, g.
V_A = Volume of $C_6H_5A_sO$ used, ml.
N_A = Normality of standard phenylarsine oxide solution, $g = eq/liter$.
0.2039 = Conversion factor

(6 eq. I_2/mole $K_2Cr_2O_7$) (1,000 ml/liter)/(249.2 g $K_2Cr_2O_7$/mole) (100 aliquot factor)

9.3 Normality of Standard Iodine Solution.

$$N_I = N_T V_T / V_I$$

where:

N_I = Normality of standard iodine solution, g-eq/liter.
V_I = Volume of standard iodine solution used, ml.
N_T = Normality of standard (~0.01 N) thiosulfate solution; assumed to be 0.1 N_S, g-eq/liter.
V_T = Volume of thiosulfate solution used, ml.

NOTE.—If phenylarsine oxide is used intead of thiosulfate, replace N_T and V_T in Equation 9.3 with N_A and V_{AS}, respectively (see sections 8.1.1 and 8.1.3).

9.4 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20° C) and 760 mm Hg.

$$V_{m(std)} = V_m Y [(T_{std}/T_m)(P_{bar}/P_{std})]$$

where:

$V_{m(std)}$ = Volume at standard conditions of gas sample through the dry gas meter, standard liters.
V_m = Volume of gas sample through the dry gas meter (meter conditions), liters.
T_{std} = Absolute temperature at standard conditions, 293° K.
T_m = Average dry gas meter temperature, °K.
P_{bar} = Barometric pressure at the sampling site, mm Hg
P_{std} = Absolute pressure at standard conditions, 760 mm Hg.
Y = Dry gas meter calibration factor.

9.5 *Concentration of H_2S.* Calculate the concentration of H_2S in the gas stream at standard conditions using the following equation:

$$C_{H_2S} = K[(V_{IT}N_I - V_{TT}N_T)\text{ sample} - (V_{IT}N_I - V_{TT}N_T)\text{ blank}]/V_{m(std)}$$

where (metric units):

C_{H_2S} = Concentration of H_2S at standard conditions, mg/dscm.
K = Conversion factor = 17.04×10^3

(34.07 g/mole H_2S) (1,000 liters/m^3) (1,000 mg/g)/=(1,000 ml/liter) ($2H_2S$ eq/mole)

V_{IT} = Volume of standard iodine solution = 50.0 ml.
N_I = Normality of standard iodine solution, g-eq/liter.
V_{TT} = Volume of standard (~0.01 N) sodium thiosulfate solution, ml.
N_T = Normality of standard sodium thiosulfate solution, g-eq/liter.
$V_{m(std)}$ = Dry gas volume at standard conditions, liters.

NOTE.—If phenylarsine oxide is used instead of thiosulfate, replace N_T and V_{TT} in Equation 9.5 with N_A and V_{AT}, respectively (see Sections 7.3.1 and 8.1.3).

10. *Stability.* The absorbing solution is stable for at least 1 month. Sample recovery and analysis should begin within 1 hour of sampling to minimize oxidation of the acidified cadmium sulfide. Once iodine has been added to the sample, the remainder of the analysis procedure must be completed according to sections 7.2.2 through 7.3.2.

11. *Bibliography.*

11.1 Determination of Hydrogen Sulfide, Ammoniacal Cadmium Chloride Method. API Method 772-54. In: Manual on Disposal of Refinery Wastes, Vol. V: Sampling and Analysis of Waste Gases and Particulate Matter, American Petroleum Institute, Washington, D.C., 1954.

11.2 Tentative Method of Determination of Hydrogen Sulfide and Mercaptan Sulfur in Natural Gas, Natural Gas Processors Association, Tulsa, Okla., NGPA Publication No. 2265-65, 1965.

11.3 Knoll, J. E., and M. R. Midgett. Determination of Hydrogen Sulfide in Refinery Fuel Gases, Environmental Monitoring Series, Office of Research and Development, USEPA, Research Triangle Park, N.C. 27711, EPA 600/4-77-007.

11.4 Scheil, G. W., and M. C. Sharp. Standardization of Method 11 at a Petroleum Refinery, Midwest Research Institute Draft Report for USEPA, Office of Research and Development, Research Triangle Park, N.C. 27711, EPA Contract No. 68-02-1098, August 1976, EPA 600/4-77-088a (Volume 1) and EPA 600/4-77-088b (Volume 2).

(Secs. 111, 114, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7414, 7601).)

Method 13A. Determination of Total Fluoride Emissions From Stationary Sources; SPADNS Zirconium Lake Method [14,113]

1. Applicability and Principle

1.1 Applicability. This method applies to the determination of fluoride (F) emissions from sources as specified in the regulations. It does not measure fluorocarbons, such as freons.

1.2 Principle. Gaseous and particulate F are withdrawn isokinetically from the source and collected in water and on a filter. The total F is then determined by the SPADNS Zirconium Lake colorimetric method.

2. Range and Sensitivity

The range of this method is 0 to 1.4 μg F/ml. Sensitivity has not been determined.

3. Interferences

Large quantities of chloride will interfere with the analysis, but this interference can be prevented by adding silver sulfate into the distillation flask (see Section 7.3.4). If chloride ion is present, it may be easier to use the Specific Ion Electrode Method (Method 13B). Grease on sample-exposed surfaces may cause low F results due to adsorption.

4. Precision, Accuracy, and Stability

4.1 Precision. The following estimates are based on a collaborative test done at a primary aluminum smelter. In the test, six laboratories each sampled the stack simultaneously using two sampling trains for a total of 12 samples per sampling run. Fluoride concentrations encountered during the test ranged from 0.1 to 1.4 mg F/m³. The within-laboratory and between-laboratory standard deviations, which include sampling and analysis errors, were 0.044 mg F/m³ with 60 degrees of freedom and 0.064 mg F/m³ with five degrees of freedom, respectively.

4.2 Accuracy. The collaborative test did not find any bias in the analytical method.

4.3 Stability. After the sample and colorimetric reagent are mixed, the color formed is stable for approximately 2 hours. A 3°C temperature difference between the sample and standard solutions produces an error of approximately 0.005 mg F/liter. To avoid this error, the absorbances of the sample and standard solutions must be measured at the same temperature.

5. Apparatus

5.1 Sampling Train. A schematic of the sampling train is shown in Figure 13A-1; it is similar to the Method 5 train except the filter position is interchangeable. The sampling train consists of the following components:

5.1.1 Probe Nozzle, Pitot Tube, Differential Pressure Gauge, Filter Heating System, Metering System, Barometer, and Gas Density Determination Equipment. Same as Method 5, Sections 2.1.1, 2.1.3, 2.1.4, 2.1.6, 2.1.8, 2.1.9, and 2.1.10. When moisture condensation is a problem, the filter heating system is used.

5.1.2 Probe Liner. Borosilicate glass or 316 stainless steel. When the filter is located immediately after the probe, the tester may use a probe heating system to prevent filter plugging resulting from moisture condensation, but the tester shall not allow the temperature in the probe to exceed 120±14°C (248±25°F).

5.1.3 Filter Holder. With positive seal against leakage from the outside or around the filter. If the filter is located between the probe and first impinger, use borosilicate glass or stainless steel with a 20-mesh stainless steel screen filter support and a silicone rubber gasket, do not use a glass frit or a sintered metal filter support. If the filter is located between the third and fourth impingers, the tester may use borosilicate glass with a glass frit filter support and a silicone rubber gasket. The tester may also use other materials of construction with approval from the Administrator.

5.1.4 Impingers. Four impingers connected as shown in Figure 13A-1 with ground-glass (or equivalent), vacuum-tight fittings. For the first, third, and fourth impingers, use the Greenburg-Smith design, modified by replacing the tip with a 1.3-cm-inside-diameter (½ in.) glass tube extending to 1.3 cm (½ in.) from the bottom of the flask. For the second impinger, use a Greenburg-Smith impinger with the standard tip. The tester may use modifications (e.g., flexible connections between the impingers or materials other than glass), subject to the approval of the Administrator. Place a thermometer, capable of measuring temperature to within 1°C (2°F), at the outlet of the fourth impinger for monitoring purposes.

5.2 Sample Recovery. The following items are needed:

5.2.1 Probe-Liner and Probe-Nozzle Brushes, Wash Bottles, Graduated Cylinder and/or Balance, Plastic Storage Containers, Rubber Policeman, Funnel. Same as Method 5, Sections 2.2.1 to 2.2.2 and 2.2.5 to 2.2.8, respectively.

5.2.2 Sample Storage Container. Wide-mouth, high-density-polyethylene bottles for impinger water samples, 1-liter.

5.3 Analysis. The following equipment is needed:

5.3.1 Distillation Apparatus. Glass distillation apparatus assembled as shown in Figure 13A-2.

5.3.2 Bunsen Burner.

5.3.3 Electric Muffle Furnace. Capable of heating to 600°C.

5.3.4 Crucibles. Nickel, 75- to 100-ml.

5.3.5 Beakers. 500-ml and 1500-ml.

5.3.6 Volumetric Flasks. 50-ml.

5.3.7 Erlenmeyer Flasks or Plastic Bottles. 500-ml.

5.3.8 Constant Temperature Bath. Capable of maintaining a constant temperature of ±1.0°C at room temperature conditions.

5.3.9 Balance. 300-g capacity to measure to ±0.5 g.

5.3.10 Spectrophotometer. Instrument that measures absorbance at 570 nm and provides at least a 1-cm light path.

5.3.11 Spectrophotometer Cells. 1-cm pathlength.

6. Reagents

6.1 Sampling. Use ACS reagent-grade chemicals or equivalent, unless otherwise specified. The reagents used in sampling are as follows:

6.1.1 Filters.

6.1.1.1 If the filter is located between the third and fourth impingers, use a Whatman [1] No. 1 filter, or equivalent, sized to fit the filter holder.

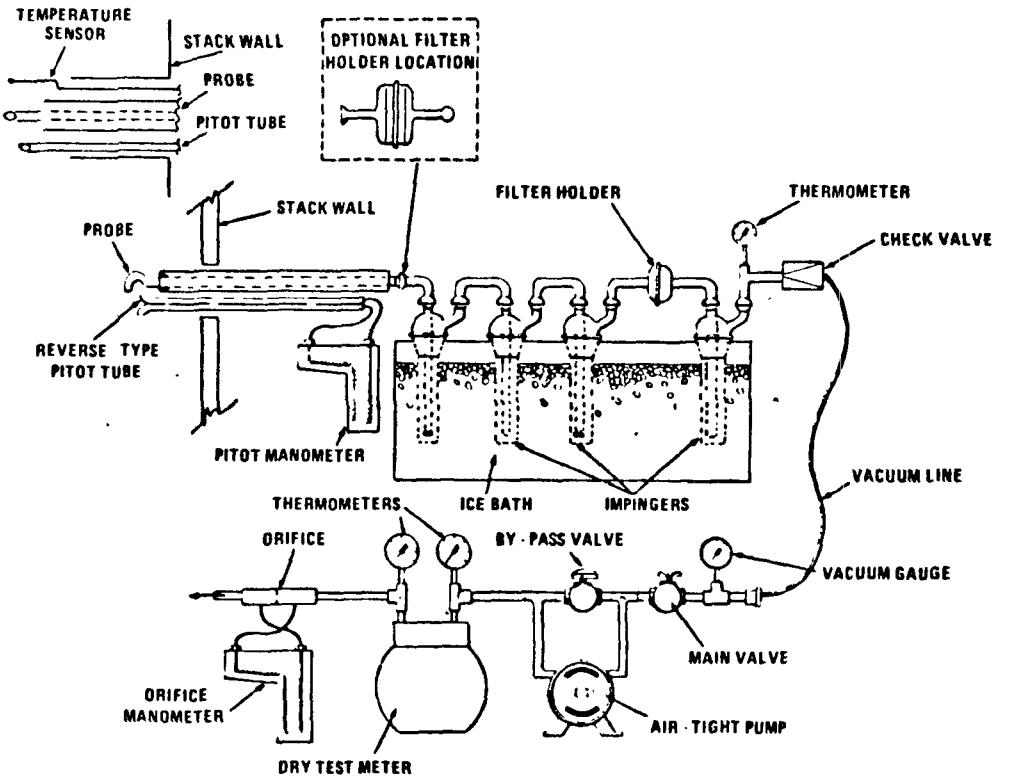


Figure 13A 1. Fluoride sampling train.

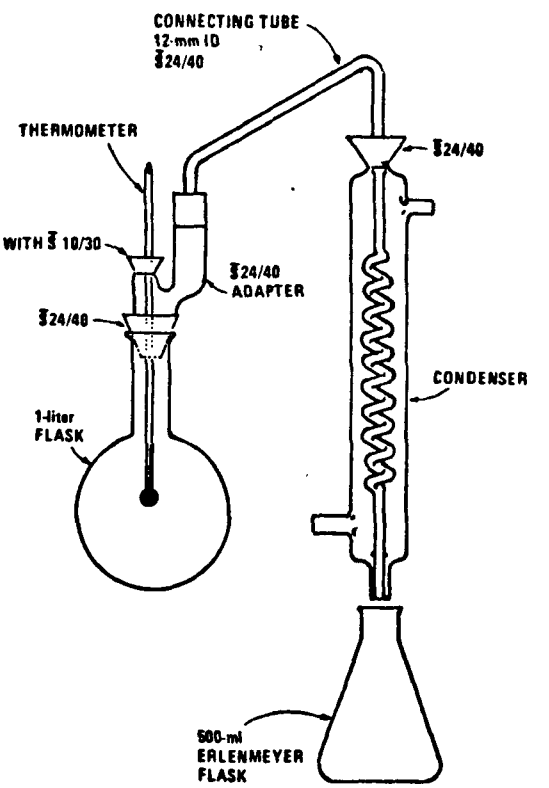


Figure 13A-2. Fluoride distillation apparatus.

6.1.1.2 If the filter is located between the probe and first impinger, use any suitable medium (e.g., paper organic membrane) that conforms to the following specifications: (1) The filter can withstand prolonged exposure to temperatures up to 135°C (275°F). (2) The filter has at least 95 percent collection efficiency (<5 percent penetration) for 0.3 μm dioctyl phthalate smoke particles. Conduct the filter efficiency test before the test series, using ASTM Standard Method D 2986–71, or use test data from the supplier's quality control program. (3) The filter has a low F blank value (<0.015 mg F/cm² of filter area). Before the test series, determine the average F blank value of at least three filters (from the lot to be used for sampling) using the applicable procedures described in Sections 7.3 and 7.4 of this method. In general, glass fiber filters have high and/or variable F blank values, and will not be acceptable for use.

6.1.2 Water. Deionized distilled, to conform to ASTM Specification D 1193–74, Type 3. If high concentrations of organic matter are not expected to be present, the analyst may delete the potassium permanganate test for oxidizable organic matter.

6.1.3 Silica Gel, Crushed Ice, and Stopcock Grease. Same as Method 5, Section 3.1.2, 3.1.4, and 3.1.5, respectively.

6.2 Sample Recovery. Water, from same container as described in Section 6.1.2, is needed for sample recovery.

6.3 Sample Preparation and Analysis. The reagents needed for sample preparation and analysis are as follows:

6.3.1 Calcium Oxide (CaO). Certified grade containing 0.005 percent F or less.

6.3.2 Phenolphthalein Indicator. Dissolve 0.1 g of phenolphthalein in a mixture of 50 ml of 90 percent ethanol and 50 ml of deionized distilled water.

6.3.3 Silver Sulfate (Ag_2SO_4).

6.3.4 Sodium Hydroxide (NaOH). Pellets.

6.3.5 Sulfuric Acid (H_2SO_4), Concentrated.

6.3.6 Sulfuric Acid, 25 percent (V/V). Mix 1 part of concentrated H_2SO_4 with 3 parts of deionized distilled water.

6.3.7 Filters Whatman No. 541, or equivalent

6.3.8 Hydrochloric Acid (HCl), Concentrated.

6.3.9 Water. From same container as described in Section 6.1.2.

6.3.10 Fluoride Standard Solution, 0.01 mg F/ml. Dry in an oven at 110°C for at least 2 hours. Dissolve 0.2210 g of NaF in 1 liter of deionized distilled water. Dilute 100 ml of this solution to 1 liter with deionized distilled water.

6.3.11 SPADNS Solution [4, 5 dihydroxy-3-(p-sulfophenylazo)-2,7-naphthalene-disulfonic acid trisodium salt]. Dissolve 0.960 ± 0.010 g of SPADNS reagent in 500 ml deionized distilled water. If stored in a well-sealed bottle protected from the sunlight, this solution is stable for at least 1 month.

6.3.12 Spectrophotometer Zero Reference Solution Prepare daily. Add 10 ml of SPADNS solution (6.3.11) to 100 ml deionized distilled water, and acidify with a solution prepared by diluting 7 ml of concentrated HCl to 10 ml with deionized distilled water.

6.3.13 SPADNS Mixed Reagent. Dissolve 0.135 ± 0.005 g of zirconyl chloride octahydrate ($ZrOCl_2 \cdot 8H_2O$) in 25 ml of deionized distilled water. Add 350 ml of concentrated HCl, and dilute to 500 ml with deionized distilled water. Mix equal volumes of this solution and SPADNS solution to form a single reagent. This reagent is stable for at least 2 months.

7. Procedure

7.1 Sampling. Because of the complexity of this method, testers should be trained and experienced with the text procedures to assure reliable results.

7.1.1 Pretest Preparation. Follow the general procedure given in Method 5, Section 4.1.1, except the filter need not be weighed.

7.1.2 Preliminary Determinations. Follow the general procedure given in Method 5, Section 4.1.2., except the nozzle size selected must maintain isokinetic sampling rates below 28 liters/min (1.0 cfm).

7.1.3 Preparation of Collection Train. Follow the general procedure given in Method 5, Section 4.1.3, except for the following variations:

Place 100 ml of deionized distilled water in each of the first two impingers, and leave the third impinger empty. Transfer approximately 200 to 300 g of preweighed silica gel from its container to the fourth impinger.

Assemble the train as shown in Figure 13A–1 with the filter between the third and fourth impingers. Alternatively, if a 20-mesh stainless steel screen is used for the filter support, the tester may place the filter between the probe and first impinger. The tester may also use a filter heating system to prevent moisture condensation, but shall not allow the temperature around the filter holder to exceed 120 ± 14°C (248 ± 25°F). Record the filter location on the data sheet.

7.1.4 Leak-Check Procedures. Follow the leak-check procedures given in Method 5, Sections 4.1.4.1 (Pretest Leak-Check), 4.1.4.2 (Leak-Checks During the Sample Run), and 4.1.4.3 (Post-Test Leak-Check).

7.1.5 Fluoride Train Operation. Follow the general procedure given in Method 5, Section 4.1.5, keeping the filter and probe temperatures (if applicable) at 120 ± 14°C (248 ± 25°F) and isokinetic sampling rates below 28 liters/min (1.0 cfm). For each run, record the data required on a data sheet such as the one shown in Method 5, Figure 5–2.

7.2 Sample Recovery. Begin proper cleanup procedure as soon as the probe is removed from the stack at the end of the sampling period.

Allow the probe to cool When it can be safely handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it to keep from losing part of the sample. Do not cap off the probe tip tightly while the sampling train is cooling down, because a vacuum would form in the filter holder, thus drawing impinger water backward.

Before moving the sample train to the cleanup site, remove the probe from the sample train, wipe off the silicone grease, and cap the open outlet of the probe. Be careful not to lose any condensate, if present Remove the filter assembly, wipe off the silicone grease from the filter holder inlet, and cap this inlet. Remove the umbilical cord from the last impinger, and cap the impinger. After wiping off the silicone grease, cap off the filter holder outlet and any open impinger inlets and outlets. The tester may use ground-glass stoppers, plastic caps, or serum caps to close these openings.

Transfer the probe and filter-impinger assembly to an area that is clean and protected from the wind so that the chances of contaminating or losing the sample is minimized.

Inspect the train before and during disassembly, and note any abnormal conditions. Treat the samples as follows:

7.2.1 *Container No. 1* (Probe, Filter, and Impinger Catches). Using a graduated cylinder, measure to the nearest ml, and record the volume of the water in the first three impingers; include any condensate in the probe in this determination. Transfer the impinger water from the graduated cylinder into this polyethylene container. Add the filter to this container. (The filter may be handled separately using procedures subject to the Administrator's approval.) Taking care that dust on the outside of the probe or other exterior surfaces does not get into the sample, clean all sample-exposed surfaces (including the probe nozzle, probe fitting, probe liner, first three impingers, impinger connectors, and filter holder) with deionized distilled water. Use less than 500 ml for the entire wash. Add the washings to the sampler container. Perform the deionized distilled water rinses as follows:

Carefully remove the probe nozzle and rinse the inside surface with deionized distilled water from a wash bottle. Brush with a Nylon bristle brush, and rinse until the rinse shows no visible particles, after which make a final rinse of the inside surface. Brush and rinse the inside parts of the Swagelok fitting with deionized distilled water in a similar way.

Rinse the probe liner with deionized distilled water. While squirting the water into the upper end of the probe, tilt and rotate the probe so that all inside surfaces will be wetted with water. Let the water drain from the lower end into the sample container. The tester may use a funnel (glass or polyethylene) to aid in transferring the liquid washes to the container. Follow the rinse with a probe brush. Hold the probe in an inclined position, and squirt deionized distilled water into the upper end as the probe brush is being pushed with a twisting action through the probe. Hold the sample container underneath the lower end of the probe, and catch any water and particulate matter that is brushed from the probe. Run the brush through the probe three times or more. With stainless steel or other metal probes, run the brush through in the above prescribed manner at least six times since metal probes have small crevices in which particulate matter can be entrapped. Rinse the brush with deionized distilled water, and quantitatively collect these washings in the sample container. After the brushing, make a final rinse of the probe as described above.

It is recommended that two people clean the probe to minimize sample losses. Between sampling runs, keep brushes clean and protected from contamination.

Rinse the inside surface of each of the first three impingers (and connecting glassware) three separate times. Use a small portion of deionized distilled water for each rinse, and brush each sample-exposed surface with a Nylon bristle brush, to ensure recovery of fine particulate matter. Make a final rinse of each surface and of the brush.

After ensuring that all joints have been wiped clean of the silicone grease, brush and rinse with deionized distilled water the inside of the filter holder (front-half only, if filter is positioned between the third and fourth impingers). Brush and rinse each surface three times or more if needed. Make a final rinse of the brush and filter holder.

After all water washings and particulate matter have been collected in the sample container, tighten the lid so that water will not leak out when it is shipped to the laboratory. Mark the height of the fluid level to determine whether leakage occurs during transport. Label the container clearly to identify its contents.

7.2.2 *Container No. 2* (Sample Blank). Prepare a blank by placing an unused filter in a polyethylene container and adding a volume of water equal to the total volume in Container No. 1. Process the blank in the same manner as for Container No. 1.

7.2.3 *Container No. 3* (Silica Gel). Note the color of the indicating silica gel to determine whether it has been completely spent and make a notation of its condition. Transfer the silica gel from the fourth impinger to its original container and seal. The tester may use a funnel to pour the silica gel and a rubber policeman to remove the silica gel from the impinger. It is not necessary to remove the small amount of dust particles that may adhere to the impinger wall and are difficult to remove. Since the gain in weight is to be used for moisture calculations, do not use any water or other liquids to transfer the silica gel. If a balance is available in the field, the tester may follow the analytical procedure for Container No. 3 in Section 7.4.2.

7.3 Sample Preparation and Distillation. (Note the liquid levels in Containers No. 1 and No. 2 and confirm on the analysis sheet whether or not leakage occurred during transport. If noticeable leakage had occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results.) Treat the contents of each sample container as described below:

7.3.1 *Container No. 1* (Probe, Filter, and Impinger Catches). Filter this container's contents, including the sampling filter, through Whatman No. 541 filter paper, or equivalent, into a 1500-ml beaker.

7.3.1.1 If the filtrate volume exceeds 900 ml, make the filtrate basic (red to phenolphthalein) with NaOH, and evaporate to less than 900 ml.

7.3.1.2 Place the filtered material (including sampling filter) in a nickel crucible, add a few ml of deionized distilled water, and macerate the filters with a glass rod.

Add 100 mg CaO to the crucible, and mix the contents thoroughly to form a slurry. Add two drops of phenolphthalein indicator. Place the crucible in a hood under infrared lamps or on a hot plate at low heat. Evaporate the water completely. During the evaporation of the water, keep the slurry basic (red to phenolphthalein) to avoid loss of F. If the indicator turns colorless (acidic) during the evaporation, add CaO until the color turns red again.

After evaporation of the water, place the crucible on a hot plate under a hood and slowly increase the temperature until the Whatman No. 541 and sampling filters char. It may take several hours to completely char the filters.

Place the crucible in a cold muffle furnace. Gradually (to prevent smoking) increase the temperature to 600°C, and maintain until the contents are reduced to an ash. Remove the crucible from the furnace and allow to cool.

Add approximately 4 g of crushed NaOH to the crucible and mix. Return the crucible to the muffle furnace, and fuse the sample for 10 minutes at 600°C.

Remove the sample from the furnace, and cool to ambient temperature. Using several rinsings of warm deionized distilled water, transfer the contents of the crucible to the beaker containing the filtrate. To assure complete sample removal, rinse finally with two 20-ml portions of 25 percent H_2SO_4, and carefully add to the beaker. Mix well, and transfer to a 1-liter volumetric flask. Dilute to volume with deionized distilled water, and mix thoroughly. Allow any undissolved solids to settle.

7.3.2 *Container No. 2* (Sample Blank). Treat in the same manner as described in Section 7.3.1 above.

7.3.3 Adjustment of Acid/Water Ratio in Distillation Flask. (Use a protective shield when carrying out this procedure.) Place 400 ml of deionized distilled water in the distillation flask, and add 200 ml of concentrated H_2SO_4. (Caution: Observe standard precautions when mixing H_2SO_4 with water. Slowly add the acid to the flask with constant swirling.) Add some soft glass beads and several small pieces of broken glass tubing, and assemble the apparatus as shown in Figure 13A-2. Heat the flask until it reaches a temperature of 175°C to adjust the acid/water ratio for subsequent distillations. Discard the distillate.

7.3.4 Distillation. Cool the contents of the distillation flask to below 80°C. Pipet an aliquot of sample containing less than 10.0 mg F directly into the distillation flask, and add deionized distilled water to make a total volume of 220 ml added to the distillation flask. (To estimate the appropriate aliquot size, select an aliquot of the solution and treat as described in Section 7.4.1. This will be an approximation of the F content because of possible interfering ions.) Note: If the sample contains chloride, add 5 mg of Ag_2SO_4 to the flask for every mg of chloride.

Place a 250-ml volumetric flask at the condenser exit. Heat the flask as rapidly as possible with a Bunsen burner, and collect all the distillate up to 175°C. During heatup, play the burner flame up and down the side of the flask to prevent bumping. Conduct the distillation as rapidly as possible (15 minutes or less). Slow distillations have been found to produce low F recoveries. Caution: Be careful not to exceed 175°C to avoid causing H_2SO_4 to distill over.

If F distillation in the mg range is to be followed by a distillation in the fractional mg range, add 220 ml of deionized distilled water and distill it over as in the acid adjustment step to remove residual F from the distillation system.

The tester may use the acid in the distillation flask until there is carry-over of interferences or poor F recovery. Check for these every tenth distillation using a deionized distilled water blank and a standard solution. Change the acid whenever the F recovery is less than 90 percent or the blank value exceeds 0.1 μg/ml.

7.4 Analysis.

7.4.1 Containers No. 1 and No. 2. After distilling suitable aliquots from Containers No. 1 and No. 2 according to Section 7.3.4, dilute the distillate in the volumetric flasks to exactly 250 ml with deionized distilled water, and mix thoroughly. Pipet a suitable aliquot of each sample distillate (containing 10 to 40 μg F/ml) into a beaker, and dilute to 50 ml with deionized distilled water. Use the same aliquot size for the blank. Add 10 ml of SPADNS mixed reagent (6.3.13), and mix thoroughly.

After mixing, place the sample in a constant-temperature bath containing the standard solutions (see Section 8.2) for 30 minutes before reading the absorbance on the spectrophotometer.

Set the spectrophotometer to zero absorbance at 570 nm with the reference solution (6.3.12), and check the spectrophotometer calibration with the standard solution. Determine the absorbance of the samples, and determine the concentration from the calibration curve. If the concentration does not fall within the range of the calibration curve, repeat the procedure using a different size aliquot.

7.4.2 *Container No. 3* (Silica Gel). Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g using a balance. The tester may conduct this step in the field.

8. Calibration

Maintain a laboratory log of all calibrations.

8.1 Sampling Train. Calibrate the sampling train components according to the indicated sections in Method 5: Probe Nozzle (Section 5.1); Pitot Tube (Section 5.2); Metering System (Section 5.3); Probe heater (Section 5.4); Temperature Gauges (Section 5.5); Leak Check of Metering System (Section 5.6); and Barometer (Section 5.7).

8.2 Spectrophotometer. Prepare the blank standard by adding 10 ml of SPADNS mixed reagent to 50 ml of deionized distilled water. Accurately prepare a series of standards from the 0.01 mg F/ml standard fluoride solution (6.3.10) by diluting 0, 2, 4, 6, 8, 10, 12, and 14 ml to 100 ml with deionized distilled water. Pipet 50 ml from each solution and transfer each to a separate 100-ml beaker. Then add 10 ml of SPADNS mixed reagent to each. These standards will contain 0, 10, 20, 30, 40 50, 60, and 70 μg F (0 to 1.4 μg/ml), respectively.

After mixing, place the reference standards and reference solution in a constant temperature bath for 30 minutes before reading the absorbance with the spectrophotometer. Adjust all samples to this same temperature before analyzing.

With the spectrophotometer at 570 nm, use the reference solution (6.3.12) to set the absorbance to zero.

Determine the absorbance of the standards Prepare a calibration curve by plotting μg F/50 ml versus absorbance on linear graph paper. Prepare the standard *curve initially and thereafter whenever the* SPADNS mixed reagent is newly made. Also, run a calibration standard with each set of samples and if it differs from the calibration curve by ±2 percent, prepare a new standard curve.

9. Calculations

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation. Other forms of the equations may be used, provided that they yield equivalent results.

9.1 Nomenclature.

A_d = Aliquot of distillate taken for color development, ml.

A_t = Aliquot of total sample added to still, ml.

B_{ws} = Water vapor in the gas stream, proportion by volume.

C_s = Concentration of F in stack gas, mg/m³, dry basis, corrected to standard conditions of 760 mm Hg (29.92 in. Hg) and 293°K (528°R).

F_t = Total F in sample, mg.

μg F = Concentration from the calibration curve, μg.

T_m = Absolute average dry gas meter temperature (see Figure 5–2 of Method 5), °K (°R).

T_s = Absolute average stack gas temperature (see Figure 5–2 of Method 5), °K (°R).

V_d = Volume of distillate collected, ml.

$V_{m(std)}$ = Volume of gas sample as measured by dry gas meter, corrected to standard conditions, dscm (dscf).

V_t = Total volume of F sample, after final dilution, ml.

$V_{w(std)}$ = Volume of water vapor in the gas sample, corrected to standard conditions, scm (scf).

9.2 Average Dry Gas Meter Temperature and Average Orifice Pressure Drop. See data sheet (Figure 5–2 of Method 5).

9.3 Dry Gas Volume. Calculate $V_{m(std)}$ and adjust for leakage, if necessary, using the equation in section 6.3 of Method 5.

9.4 Volume of Water Vapor and Moisture Content. Calculate the volume of water vapor $V_{w(std)}$ and moisture content B_{ws} from the data obtained in this method (Figure 13A–1); use Equations 5–2 and 5–3 of Method 5.

9.5 Concentration.

9.5.1 Total Fluoride in Sample. Calculate the amount of F in the sample using the following equation:

$$F_t = 10^{-3} \frac{V_t}{A_t} \frac{V_d}{A_d} (\mu g\ F) \qquad \text{Eq. 13A-1}$$

9.5.2 Fluoride Concentration in Stack Gas. Determine the F concentration in the stack gas using the following equation:

$$C_s = K \frac{F_t}{V_{m(std)}} \qquad \text{Eq. 13A-2}$$

Where:

K = 35.31 ft³/m³ if $V_{m(std)}$ is expressed in English units.

= 1.00 m³/m³ if $V_{m(std)}$ is expressed in metric units.

9.6 Isokinetic Variation and Acceptable Results. Use Method 5, Sections 6.11 and 6.12.

10. Bibliography

1. Bellack, Ervin, Simplified Fluoride Distillation Method. Journal of the American Water Works Association. *50*:5306. 1958.

2. Mitchell, W. J., J. C. Suggs, and F. J. Bergman. Collaborative Study of EPA method 13A and Method 13B. Publication No. EPA–600/4–77–050. Environmental Protection Agency. Research Triangle Park, North Carolina. December 1977.

3. Mitchell, W. J. and M. R. Midgett. Adequacy of Sampling Trains and Analytical Procedures Used for Fluoride. Atm. Environ. *10*:865–872. 1976.

Method 13B. Determination of Total Fluoride Emissions From Stationary Sources; Specific Ion Electrode Method [14,113]

1. Applicability and Principle

1.1 Applicability. This method applies to the determination of fluoride (F) emissions from stationary sources as specified in the regulations. It does not measure fluorocarbons, such as freons.

1.2 Principle. Gaseous and particulate F are withdrawn isokinetically from the source and collected in water and on a filter. The total F is then determined by the specific ion electrode method.

2. Range and Sensitivity

The range of this method is 0.02 to 2.000 μg F/ml; however, measurements of less than 0.1 μg F/ml require extra care. Sensitivity has not been determined.

3. Interferences

Grease on sample-exposed surfaces may cause low F results because of adsorption.

4. Precision and Accuracy

4.1 Precision. The following estimates are based on a collaborative test done at a primary aluminum smelter. In the test, six laboratories each sampled the stack simultaneously using two sampling trains for a total of 12 samples per sampling run. Fluoride concentrations encountered during the test ranged from 0.1 to 1.4 mg F/m³. The within-laboratory and between-laboratory standard deviations, which include sampling and analysis errors, are 0.037 mg F/m³ with 60 degrees of freedom and 0.056 mg F/m³ with five degrees of freedom, respectively.

4.2 Accuracy. The collaborative test did not find any bias in the analytical method.

5. Apparatus

5.1 Sampling Train and Sample Recovery. Same as Method 13A, Sections 5.1 and 5.2, respectively.

5.2 Analysis. The following items are needed:

5.2.1 Distillation Apparatus, Bunsen Burner, Electric Muffle Furnace, Crucibles, Beakers, Volumetric Flasks, Erlenmeyer Flasks or Plastic Bottles, Constant Temperature Bath, and Balance. Same as Method 13A, Sections 5.3.1 to 5.3.9, respectively, except include also 100-ml polyethylene beakers.

5.2.2 Fluoride Ion Activity Sensing Electrode.

5.2.3 Reference Electrode. Single junction, sleeve type.

5.2.4 Electrometer. A pH meter with millivolt-scale capable of ±0.1-mv resolution, or a specific ion meter made specifically for specific ion use.

5.2.5 Magnetic Stirrer and TFE [2] Fluorocarbon-Coated Stirring Bars.

[2] Mention of any trade name or specific product does not constitute endorsement by the Environmental Protection Agency.

6. Reagents

6.1 Sampling and Sample Recovery. Same as Method 13A, Sections 6.1 and 6.2, respectively.

6.2 Analysis. Use ACS reagent grade chemicals (or equivalent), unless otherwise specified. The reagents needed for analysis are as follows:

6.2.1 Calcium Oxide (CaO). Certified grade containing 0.005 percent F or less.

6.2.2 Phenolphthalein Indicator. Dissolve 0.1 g of phenolphthalein in a mixture of 50 ml of 90 percent ethanol and 50 ml deionized distilled water.

6.2.3 Sodium Hydroxide (NaOH). Pellets.

6.2.4 Sulfuric Acid (H_2SO_4). Concentrated.

6.2.5 Filters. Whatman No. 541, or equivalent.

6.2.6 Water. From same container as 6.1.2 of Method 13A.

6.2.7 Sodium Hydroxide, 5 M. Dissolve 20 g of NaOH in 100 ml of deionized distilled water

6.2.8 Sulfuric Acid, 25 percent (V/V). Mix 1 part of concentrated H_2SO_4 with 3 parts of deionized distilled water.

6.2.9 Total Ionic Strength Adjustment Buffer (TISAB). Place approximately 500 ml of deionized distilled water in a 1-liter beaker. Add 57 ml of glacial acetic acid, 58 g of sodium chloride, and 4 g of cyclohexylene dinitrilo tetraacetic acid. Stir to dissolve. Place the beaker in a water bath to cool it. Slowly add 5 M NaOH to the solution, measuring the pH continuously with a calibrated pH/reference electrode pair, until the pH is 5.3. Cool to room temperature. Pour into a 1-liter volumetric flask, and dilute to volume with deionized distilled water. Commercially prepared TISAB may be substituted for the above.

6.2.10 Fluoride Standard Solution, 0.1 M. Oven dry some sodium fluoride (NaF) for a minimum of 2 hours at 110°C, and store in a desiccator. Then add 4.2 g of NaF to a 1-liter volumetric flask, and add enough deionized distilled water to dissolve. Dilute to volume with deionized distilled water.

7. Procedure

7.1 Sampling, Sample Recovery, and Sample Preparation and Distillation. Same as Method 13A, Sections 7.1, 7.2, and 7.3, respectively, except the notes concerning chloride and sulfate interferences are not applicable.

7.2 Analysis.

7.2.1 Containers No. 1 and No. 2. Distill suitable aliquots from Containers No. 1 and No. 2. Dilute the distillate in the volumetric flasks to exactly 250 ml with deionized distilled water and mix thoroughly. Pipet a 25-ml aliquot from each of the distillate and separate beakers. Add an equal volume of TISAB, and mix. The sample should be at the same temperature as the calibration standards when measurements are made. If ambient laboratory temperature fluctuates more than ±2°C from the temperature at which the calibration standards were measured, condition samples and standards in a constant-temperature bath before measurement. Stir the sample with a magnetic stirrer during measurement to minimize electrode response time. If the stirrer generates enough heat to change solution termperature, place a piece of temperature insulating material such as cork, between the stirrer and the beaker. Hold dilute samples (below 10^{-4} M fluoride ion content) in polyethylene beakers during measurement.

Insert the fluoride and reference electrodes into the solution. When a steady millivolt reading is obtained, record it. This may take several minutes. Determine concentration from the calibration curve. Between electrode measurements, rinse the electrode with distilled water.

7.2.2 Container No. 3 (Silica Gel). Same as Method 13A, Section 7.4.2.

8. Calibration

Maintain a laboratory log of all calibrations.

8.1 Sampling Train. Same as Method 13A.

8.2 Fluoride Electrode. Prepare fluoride standardizing solutions by serial dilution of the 0.1 M fluoride standard solution. Pipet 10 ml of 0.1 M fluoride standard solution into a 100-ml volumetric flask, and make up to the mark with deionized distilled water for a 10^{-2} M standard solution. Use 10 ml of 10^{-2} M solution to make a 10^{-3} M solution in the same manner. Repeat the dilution procedure and make 10^{-4} and 10^{-5} solutions.

Pipet 50 ml of each standard into a separate beaker. Add 50 ml of TISAB to each beaker. Place the electrode in the most dilute standard solution. When a steady millivolt reading is obtained, plot the value on the linear axis of semilog graph paper versus concentration on the log axis. Plot the nominal value for concentration of the standard on the log axis, e.g., when 50 ml of 10^{-2} M standard is diluted with 50 ml of TISAB, the concentration is still designated "10^{-2} M."

Between measurements soak the fluoride sensing electrode in deionized distilled water for 30 seconds, and then remove and blot dry. Analyze the standards going from dilute to concentrated standards. A straight-line calibration curve will be obtained, with nominal concentrations of 10^{-4}, 10^{-3}, 10^{-2}, and 10^{-1} fluoride molarity on the log axis plotted versus electrode potential (in mv) on the linear scale. Some electrodes may be slightly nonlinear between 10^{-5} and 10^{-4} M. If this occurs, use additional standards between these two concentrations.

Calibrate the fluoride electrode daily, and check it hourly. Prepare fresh fluoride standardizing solutions daily (10^{-2} M or less). Store fluoride standardizing solutions in polyethylene or polypropylene containers. (Note: Certain specific ion meters have been designed specifically for fluoride electrode use and give a direct readout of fluoride ion concentration. These meters may be used in lieu of calibration curves for fluoride measurements over narrow concentration ranges. Calibrate the meter according to the manufacturer's instructions.)

9. Calculations

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

9.1 Nomenclature. Same as Method 13A, Section 9.1. In addition:

M = F concentration from calibration curve, molarity.

9.2 Average Dry Gas Meter Temperature and Average Orifice Pressure Drop, Dry Gas Volume, Volume of Water Vapor and Moisture Content, Fluroide Concentration in Stack Gas, and Isokinetic Variation and Acceptable Results. Same as Method 13A, Section 9.2 to 9.4, 9.5.2, and 9.6, respectively.

9.3 Fluoride in Sample. Calculate the amount of F in the sample using the following:

$$F_t = K \frac{T_t}{A_t} (V_d) (M)$$

Where:

K = 19 mg/ml.

Equation 13B-1

10. References

1. Same as Method 13A, Citations 1 and 2 of Section 10.

2. MacLeod, Kathryn E. and Howard L. Crist. Comparison of the SPADNS—Zirconium Lake and Specific Ion Electrode Methods of Fluoride Determination in Stack Emission Samples. Analytical Chemistry. 45:1272–1273. 1973.

METHOD 14—DETERMINATION OF FLUORIDE EMISSIONS FROM POTROOM ROOF MONITORS FOR PRIMARY ALUMINUM PLANTS [27,114]

1. *Applicability and Principle.*

1.1 Applicability. This method is applicable for the determination of fluoride emissions from stationary sources only when specified by the test procedures for determining compliance with new source performance standards.

1.2 Principle. Gaseous and particulate fluoride roof monitor emissions are drawn into a permanent sampling manifold through several large nozzles. The sample is transported from the sampling manifold to ground level through a duct. The gas in the duct is sampled using Method 13A or 13B—Determination of Total Fluoride Emissions from Stationary Sources. Effluent velocity and volumetric flow rate are determined with anemometers located in the roof monitor.

2. *Apparatus.*

2.1 Velocity measurement apparatus.

2.1.1 Anemometers. Propeller anemometers, or equivalent. Each anemometer shall meet the following specifications: (1) Its propeller shall be made of polystyrene, or similar material of uniform density. To insure uniformity of performance among propellers, it is desirable that all propellers be made from the same mold. (2) The propeller shall be properly balanced, to optimize performance; (3) When the anemometer is mounted horizontally, its threshold velocity shall not exceed 15 m/min (50 fpm); (4) The measurement range of the anemometer shall extend to at least 600 m/min (2,000 fpm); (5) The anemometer shall be able to withstand prolonged exposure to dusty and corrosive environments; one way of achieving this is to continuously purge the bearings of the anemometer with filtered air during operation; (6) All anemometer components shall be properly shielded or encased, such that the performance of the anemometer is uninfluenced by potroom magnetic field effects; (7) A known relationship shall exist between the electrical output signal from the anemometer generator and the propeller shaft rpm, at a minimum of three evenly spaced rpm settings between 60 and 1800 rpm; for the 3 settings, use 60 ± 15, 900 ± 100, and 1800 ± 100 rpm. Anemometers having other types of output signals (e.g., optical) may be used, subject to the approval of the Administrator. If other types of anemometers are used, there must be a known relationship (as described above) between output signal and shaft rpm; also, each anemometer must be equipped with a suitable readout system (See Section 2.1.3).

2.1.2 Installation of anemometers.

2.1.2.1 If the affected facility consists of a single, isolated potroom (or potroom segment), install at least one anemometer for every 85 m of roof monitor length. If the length of the roof monitor divided by 85 m is not a whole number, round the fraction to the nearest whole number to determine the number of anemometers needed. For monitors that are less than 130 m in length, use at least two anemometers. Divide the monitor cross-section into as many equal areas as anemometers and locate an anemometer at the centroid of each equal area. See exception in Section 2.1.2.3.

2.1.2.2 If the affected facility consists of two or more potrooms (or potroom segments) ducted to a common control device, install anemometers in each potroom (or segment) that contains a sampling manifold. Install at least one anemometer for every 85 m of roof monitor length of the potroom (or segment). If the potroom (or segment) length divided by 85 is not a whole number, round the fraction to the nearest whole number to determine the number of anemometers needed. If the potroom (or segment) length is less than 130 m, use at least two anemometers. Divide the potroom (or segment) monitor cross-section into as many equal areas as anemometers and locate an anemometer at the centroid of each equal area. See exception in Section 2.1.2.3.

2.1.2.3 At least one anemometer shall be installed in the immediate vicinity (i.e., within 10 m) of the center of the manifold (See Section 2.2.1). For its placement in relation to the width of the monitor, there are two alternatives. The first is to make a velocity traverse of the width of the roof monitor where an anemometer is to be placed and install the anemometer at a point of average velocity along this traverse. The traverse may be made with any suitable low velocity measuring device, and shall be made during normal process operating conditions.

The second alternative, at the option of the tester, is to install the anemometer halfway across the width of the roof monitor. In this latter case, the velocity traverse need not be conducted.

2.1.3 Recorders. Recorders, equipped with suitable auxiliary equipment (e.g. transducers) for converting the output signal from each anemometer to a continuous recording of air flow velocity, or to an integrated measure of volumetric flowrate. A suitable recorder is one that allows the output signal from the propeller anemometer to be read to within 1 percent when the velocity is between 100 and 120 m/min (350 and 400 fpm). For the purpose of recording velocity, "continuous" shall mean one readout per 15-minute or shorter time interval. A constant amount of time shall elapse between readings. Volumetric flow rate may be determined by an electrical count of anemometer revolutions. The recorders or counters shall permit identification of the velocities or flowrate measured by each individual anemometer.

2.1.4 Pitot tube. Standard-type pitot tube as described in Section 2.7 of Method 2, and having a coefficient of 0.99 ± 0.01.

2.1.5 Pitot tube (optional). Isolated, Type S pitot, as described in Section 2.1 of Method 2. The pitot tube shall have a known coefficient, determined as outlined in Section 4.1 of Method 2.

2.1.6 Differential pressure gauge. Inclined manometer or equivalent, as described in Section 2.1.2 of Method 2.

2.2 Roof monitor air sampling system

2.2.1 Sampling ductwork. A minimum of one manifold system shall be installed for each potroom group (as defined in Subpart S, Section 60.191). The manifold system and connecting duct shall be permanently installed to draw an air sample from the roof monitor to ground level. A typical installation of a duct for drawing a sample from a roof monitor to ground level is shown in Figure 14-1. A plan of a manifold system that is located in a roof monitor is shown in Figure 14.2. These drawings represent a typical installation for a generalized roof monitor. The dimensions on these figures may be altered slightly to make the manifold system fit into a particular roof monitor, but the general configuration shall be followed. There shall be eight nozzles, each having a diameter of 0.40 to 0.50 m. Unless otherwise specified by the Administrator, the length of the manifold system from the first nozzle to the eighth shall be 35 m or eight percent of the length of the potroom (or potroom segment) roof monitor, whichever is greater.

The duct leading from the roof monitor manifold shall be round with a diameter of 0.30 to 0.40 m. As shown in Figure 14-2, each of the sample legs of the manifold shall have a device, such as a blast gate or valve, to enable adjustment of the flow into each sample nozzle.

The manifold shall be located in the immediate vicinity of one of the propeller anemometers (see Section 2.1.2.3) and as close as possible to the midsection of the potroom (or potroom segment). Avoid locating the manifold near the end of a potroom or in a section where the aluminum reduction pot arrangement is not typical of the rest of the potroom (or potroom segment). Center the sample nozzles in the throat of the roof monitor (see Figure 14-1). Construct all sample-exposed surfaces within the nozzles, manifold and sample duct of 316 stainless steel. Aluminum may be used if a new ductwork system is conditioned with fluoride-laden roof monitor air for a period of six weeks prior to initial testing. Other materials of construction may be used if it is demonstrated through comparative testing that there is no loss of flourides in the system. All connections in the ductwork shall be leak free.

Locate two sample ports in a vertical section of the duct between the roof monitor and exhaust fan. The sample ports shall be at least 10 duct diameters downstream and three diameters upstream from any flow disturbance such as a bend or contraction. The two sample ports shall be situated 90° apart. One of the sample ports shall be situated so that the duct can be traversed in the plane of the nearest upstream duct bend.

2.2.2 Exhaust fan. An industrial fan or blower shall be attached to the sample duct at ground level (see Figure 14-1). This exhaust fan shall have a capacity such that a large enough volume of air can be pulled through the ductwork to maintain an isokinetic sampling rate in all the sample nozzles for all flow rates normally encountered in the roof monitor.

The exhaust fan volumetric flow rate shall be adjustable so that the roof monitor air can be drawn isokinetically into the sample nozzles. This control of flow may be achieved by a damper on the inlet to the exhauster or by any other workable method.

2.3 Temperature measurement apparatus.

2.3.1 Thermocouple. Install a thermocouple in the roof monitor near the

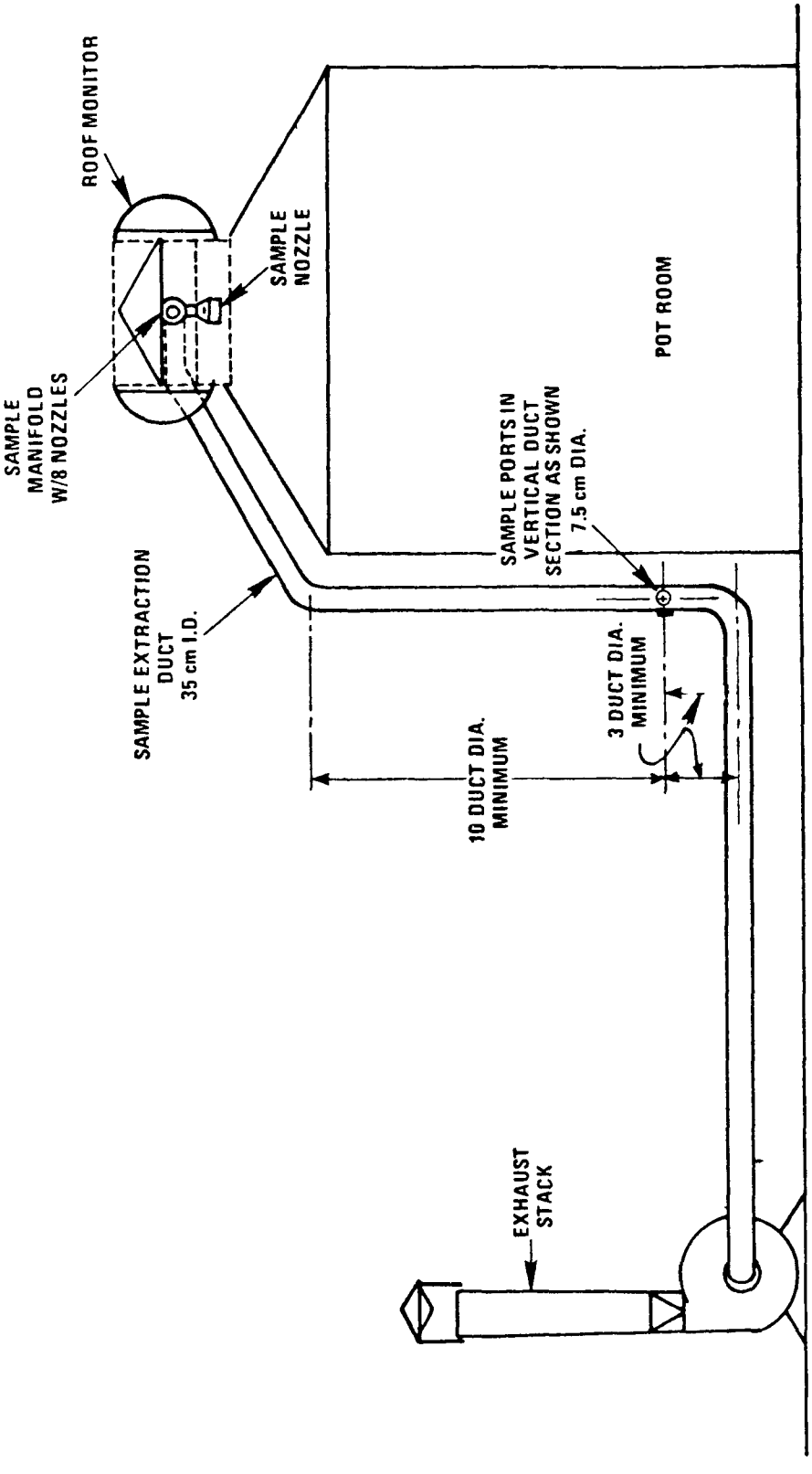


Figure 14-1. Roof monitor sampling system.

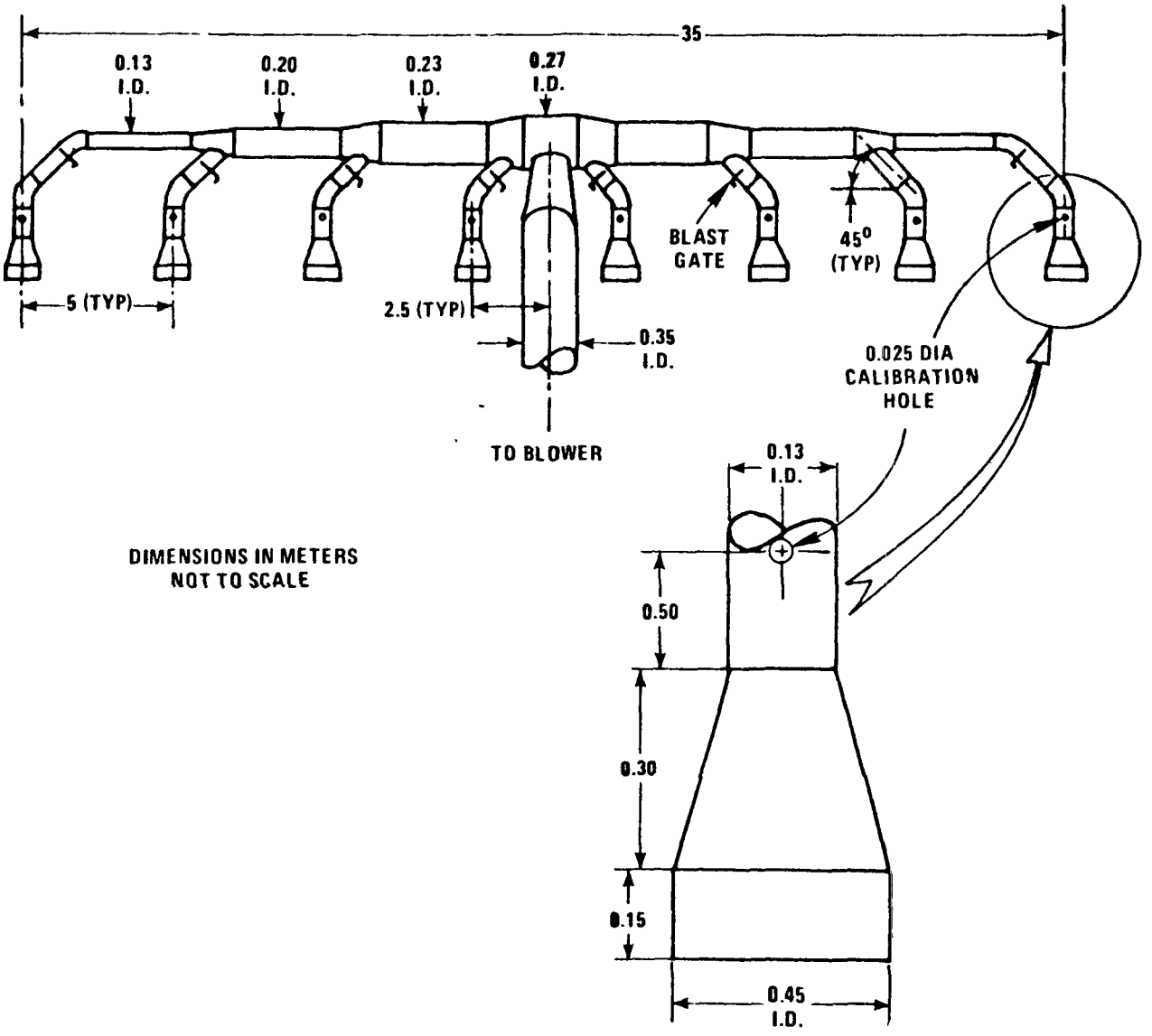


Figure 14 2. Sampling manifold and nozzles.

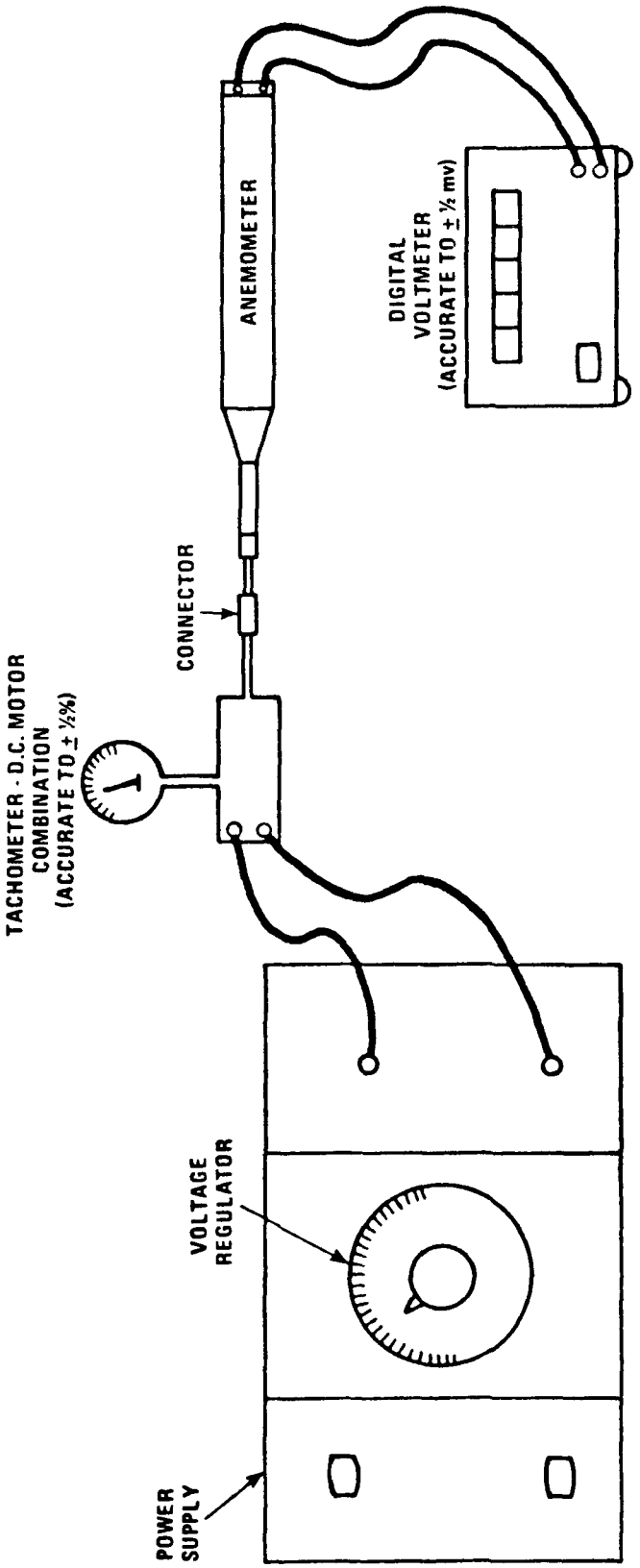


Figure 14-3. Typical RPM generator.

sample duct. The thermocouple shall conform to the specifications outlined in Section 2.3 of Method 2.

2.3.2 Signal transducer. Transducer, to change the thermocouple voltage output to a temperature readout.

2.3.3 Thermocouple wire. To reach from roof monitor to signal transducer and recorder.

2.3.4 Recorder. Suitable recorder to monitor the output from the thermocouple signal transducer

2.4 Fluoride sampling train. Use the train described in Method 13A or 13B.

3. *Reagents.*

3.1 Sampling and analysis. Use reagents described in Method 13A or 13B.

4 *Calibration.*

4.1 *Initial performance checks.* Conduct these checks within 60 days prior to the first performance test.

4.1.1 Propeller anemometers. Anemometers which meet the specifications outlined in Section 2.1.1 need not be calibrated, provided that a reference performance curve relating anemometer signal output to air velocity (covering the velocity range of interest) is available from the manufacturer. For the purpose of this method, a "reference" performance curve is defined as one that has been derived from primary standard calibration data, with the anemometer mounted vertically. "Primary standard" data are obtainable by: (1) Direct calibration of one or more of the anemometers by the National Bureau of Standards (NBS); (2) NBS-traceable calibration; or (3) Calibration by direct measurement of fundamental parameters such as length and time (e.g., by moving the anemometers through still air at measured rates of speed, and recording the output signals). If a reference performance curve is not available from the manufacturer, such a curve shall be generated, using one of the three methods described as above. Conduct a performance-check as outlined in Section 4.1.1.1 through 4.1.1.3, below. Alternatively, the tester may use any other suitable method, subject to the approval of the Administrator, that takes into account the signal output, propeller condition and threshold velocity of the anemometer.

4.1.1.1 Check the signal output of the anemometer by using an accurate rpm generator (see Figure 14–3) or synchronous motors to spin the propeller shaft at each of the three rpm settings described in Section 2.1.1 above (specification No. 7), and measuring the output signal at each setting. If, at each setting, the output signal is within ± 5 percent of the manufacturer's value, the anemometer can be used. If the anemometer performance is unsatisfactory, the anemometer shall either be replaced or repaired.

4.1.1.2 Check the propeller condition, by visually inspecting the propeller, making note of any significant damage or warpage; damaged or deformed propellers shall be replaced.

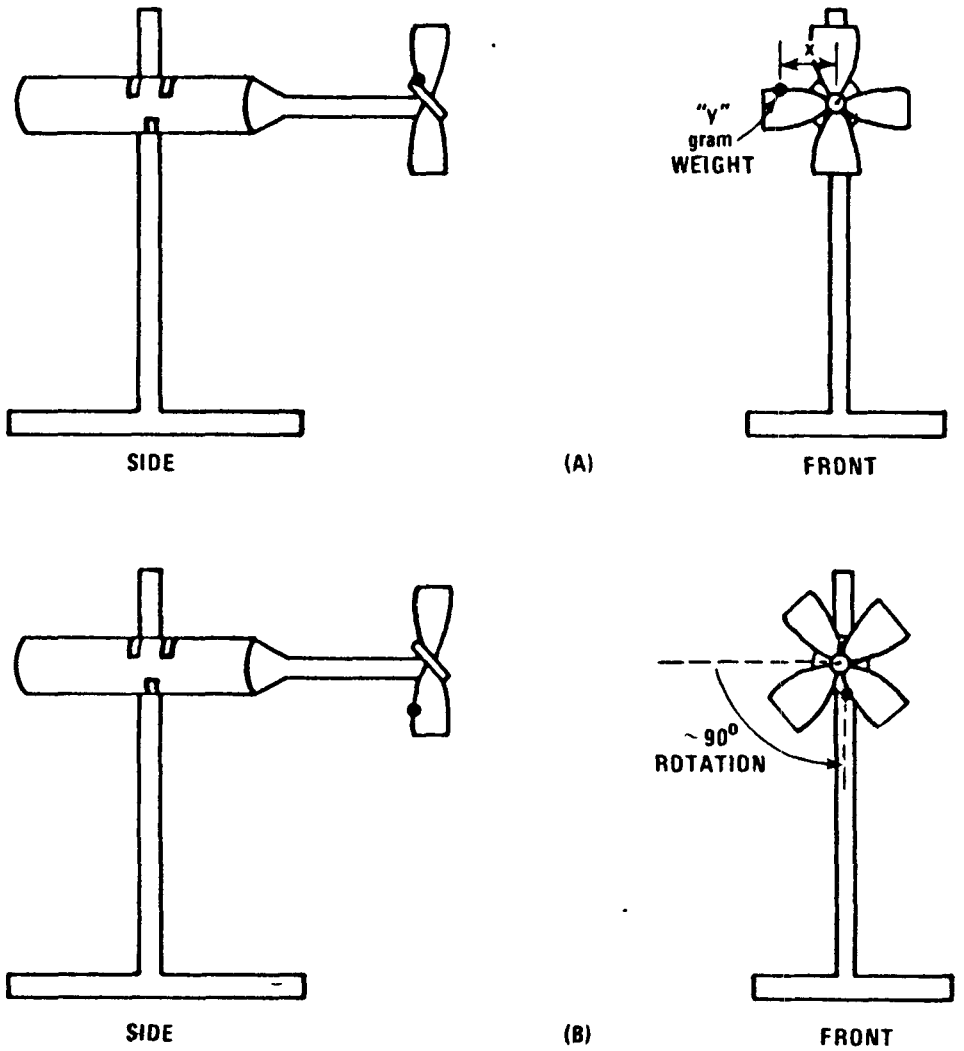


Figure 14-4. Check of anemometer starting torque. A "y" gram weight placed "x" centimeters from center of propeller shaft produces a torque of "xy" g-cm. The minimum torque which produces a 90° (approximately) rotation of the propeller is the "starting torque."

4.1.1.3 Check the anemometer threshold velocity as follows: With the anemometer mounted as shown in Figure 14-4(A), fasten a known weight (a straight-pin will suffice) to the anemometer propeller at a fixed distance from the center of the propeller shaft. This will generate a known torque: for example, a 0.1 g weight, placed 10 cm from the center of the shaft, will generate a torque of 1.0 g-cm. If the known torque causes the propeller to rotate downward, approximately 90° [see Figure 14-4(B)], then the known torque is greater than or equal to the starting torque; if the propeller fails to rotate approximately 90°, the known torque is less than the starting torque. By trying different combinations of weight and distance, the starting torque of a particular anemometer can be satisfactorily estimated. Once an estimate of the starting torque has been obtained, the threshold velocity of the anemometer (for horizontal mounting) can be estimated from a graph such as Figure 14-5 (obtained from the manufacturer). If the horizontal threshold velocity is acceptable [<15 m/min (50 fpm), when this technique is used], the anemometer can be used. If the threshold velocity of an anemometer is found to be unacceptably high, the anemometer shall either be replaced or repaired.

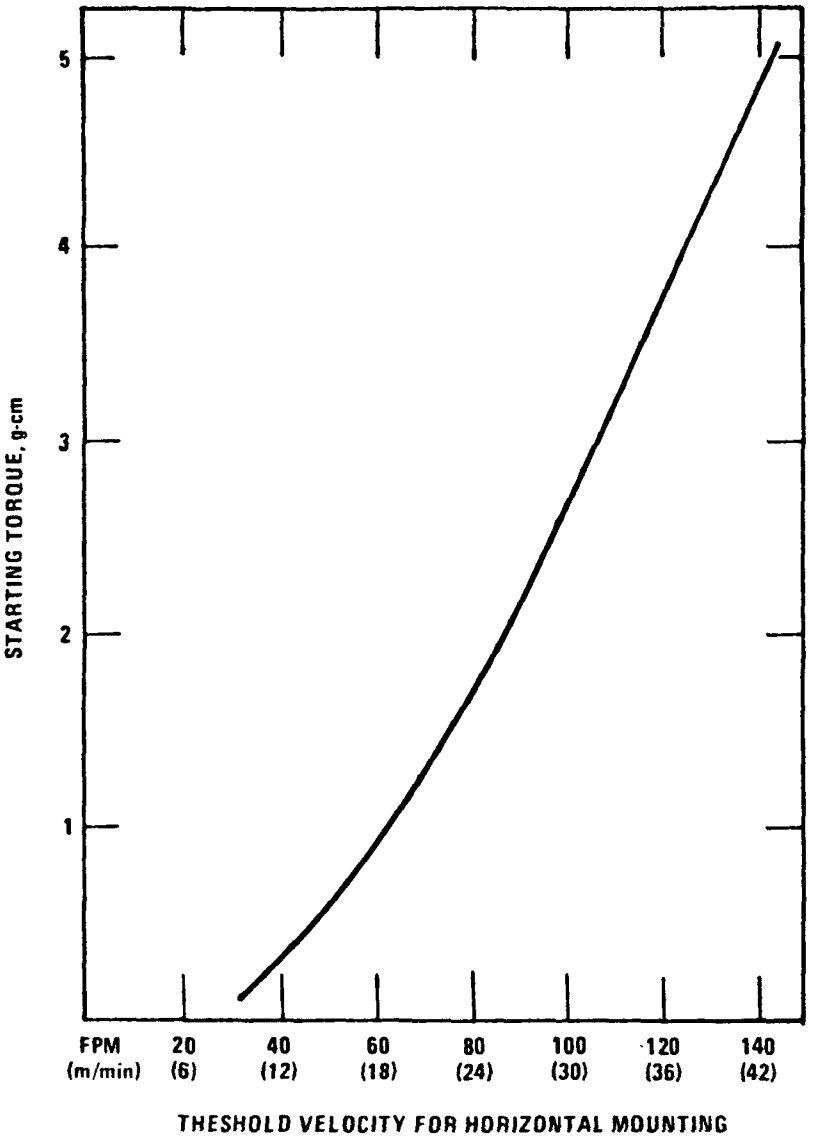


Figure 14-5. Typical curve of starting torque vs horizontal threshold velocity for propeller anemometers. Based on data obtained by R.M. Young Company, May, 1977.

4.1.2 Thermocouple. Check the calibration of the thermocouple-potentiometer system, using the procedures outlined in Section 4.3 of Method 2, at temperatures of 0, 100, and 150°C. If the calibration is off by more than 5°C at any of the temperatures, repair or replace the system; otherwise, the system can be used.

4.1.3 Recorders and/or counters. Check the calibration of each recorder and/or counter (see Section 2.1.3) at a minimum of three points, approximately spanning the expected range of velocities. Use the calibration procedures recommended by the manufacturer, or other suitable procedures (subject to the approval of the Administrator). If a recorder or counter is found to be out of calibration, by an average amount greater than 5 percent for the three calibration points, replace or repair the system; otherwise, the system can be used.

4.1.4 Manifold Intake Nozzles. In order to balance the flow rates in the eight individual nozzles, proceed as follows: Adjust the exhaust fan to draw a volumetric flow rate (refer to Equation 14–1) such that the entrance velocity into each manifold nozzle approximates the average effluent velocity in the roof monitor. Measure the velocity of the air entering each nozzle by inserting a standard pitot tube into a 2.5 cm or less diameter hole (see Figure 14–2) located in the manifold between each blast gate (or valve) and nozzle. Note that a standard pitot tube is used, rather than a type S, to eliminate possible velocity measurement errors due to cross-section blockage in the small (0.13 m diameter) manifold leg ducts. The pitot tube tip shall be positioned at the center of each manifold leg duct. Take care to insure that there is no leakage around the pitot tube, which could affect the indicated velocity in the manifold leg. If the velocity of air being drawn into each nozzle is not the same, open or close each blast gate (or valve) until the velocity in each nozzle is the same. Fasten each blast gate (or valve) so that it will remain in this position and close the pitot port holes. This calibration shall be performed when the manifold system is installed. Alternatively, the manifold may be preassembled and the flow rates balanced on the ground, before being installed.

4.2 Periodical performance checks. Twelve months after their initial installation, check the calibration of the propeller anemometers, thermocouple-potentiometer system, and the recorders and/or counters as in Section 4.1. If the above systems pass the performance checks, (i.e., if no repair or replacement of any component is necessary), continue with the performance checks on a 12-month interval basis. However, if any of the above systems fail the performance checks, repair or replace the system(s) that failed and conduct the periodical performance checks on a 3-month interval basis, until sufficient information (consult with the Administrator) is obtained to establish a modified performance check schedule and calculation procedure.

Note.—If any of the above systems fail the initial performance checks, the data for the past year need not be recalculated.

5. *Procedure.*

5.1 Roof Monitor Velocity Determination.

5.1.1 Velocity estimate(s) for setting isokinetic flow. To assist in setting isokinetic flow in the manifold sample nozzles, the anticipated average velocity in the section of the roof monitor containing the sampling manifold shall be estimated prior to each test run. The tester may use any convenient means to make this estimate (e.g., the velocity indicated by the anemometer in the section of the roof monitor containing the sampling manifold may be continuously monitored during the 24-hour period prior to the test run).

If there is question as to whether a single estimate of average velocity is adequate for an entire test run (e.g., if velocities are anticipated to be significantly different during different potroom operations), the tester may opt to divide the test run into two or more "sub-runs," and to use a different estimated average velocity for each sub-run (see Section 5.3.2.2.)

5.1.2 Velocity determination during a test run. During the actual test run, record the velocity or volumetric flowrate readings of each propeller anemometer in the roof monitor. Readings shall be taken for each anemometer every 15 minutes or at shorter equal time intervals (or continuously).

5.2 Temperature recording. Record the temperature of the roof monitor every 2 hours during the test run.

5.3 Sampling.

5.3.1 Preliminary air flow in duct. During 24 hours preceding the test, turn on the exhaust fan and draw roof monitor air through the manifold duct to condition the ductwork. Adjust the fan to draw a volumetric flow through the duct such that the velocity of gas entering the manifold nozzles approximates the average velocity of the air exiting the roof monitor in the vicinity of the sampling manifold.

5.3.2 Manifold isokinetic sample rate adjustment(s).

5.3.2.1 Initial adjustment. Prior to the test run (or first sub-run, if applicable; see Section 5.1.1 and 5.3.2.2), adjust the fan to provide the necessary volumetric flowrate in the sampling duct, so that air enters the manifold sample nozzles at a velocity equal to the appropriate estimated average velocity determined under Section 5.1.1. Equation 14–1 gives the correct stream velocity needed in the duct at the sampling location, in order for sample gas to be drawn isokinetically into the manifold nozzles. Next, verify that the correct stream velocity has been achieved, by performing a pitot tube traverse of the sample duct (using either a standard or type S pitot tube); use the procedure outlined in Method 2.

$$v_d = \frac{8\,(D_n)^2}{(D_d)^2}\,(v_m)\,\frac{1\text{ min}}{60\text{ sec}} \qquad \text{(Equation 14-1)}$$

Where:

v_d = Desired velocity in duct at sampling location, m/sec.

D_n = Diameter of a roof monitor manifold nozzle, m.

D_d = Diameter of duct at sampling location, m.

v_m = Average velocity of the air stream in the roof monitor, m/min, as determined under Section 5.1.1.

5.3.2.2 Adjustments during run. If the test run is divided into two or more "sub-runs" (see Section 5.1.1), additional isokinetic rate adjustment(s) may become necessary during the run. Any such adjustment shall be made just before the start of a sub-run, using the procedure outlined in Section 5.3.2.1 above.

Note.—Isokinetic rate adjustments are not permissible during a sub-run.

5.3.3 Sample train operation. Sample the duct using the standard fluoride train and methods described in Methods 13A and 13B. Determine the number and location of the sampling points in accordance with Method 1. A single train shall be used for the entire sampling run. Alternatively, if two or more sub-runs are performed, a separate train may be used for each sub-run; note, however, that if this option is chosen, the area of the sampling nozzle shall be the same (± 2 percent) for each train. If the test run is divided into sub-runs, a complete traverse of the duct shall be performed during each sub-run.

5.3.4 Time per run. Each test run shall last 8 hours or more; if more than one run is to be performed, all runs shall be of approximately the same (± 10 percent) length. If question exists as to the representativeness of an 8-hour test, a longer period should be selected. Conduct each run during a period when all normal operations are performed underneath the sampling manifold. For most recently-constructed plants, 24 hours are required for all potroom operations and events to occur in the area beneath the sampling manifold. During the test period, all pots in the potroom group shall be operated such that emissions are representative of normal operating conditions in the potroom group.

5.3.5 Sample recovery. Use the sample recovery procedure described in Method 13A or 13B.

5.4 Analysis. Use the analysis procedures described in Method 13A or 13B.

6. *Calculations.*

6.1 Isokinetic sampling check.

6.1.1 Calculate the mean velocity (v_m) for the sampling run, as measured by the anemometer in the section of the roof monitor containing the sampling manifold. If two or more sub-runs have been performed, the tester may opt to calculate the mean velocity for each sub-run.

6.1.2 Using Equation 14–1, calculate the expected average velocity (v_d) in the sampling duct, corresponding to each value of v_m obtained under Section 6.1.1.

6.1.3 Calculate the actual average velocity (v_s) in the sampling duct for each run or sub-run, according to Equation 2–9 of Method 2, and using data obtained from Method 13.

6.1.4 Express each value v_s from Section 6.1.3 as a percentage of the corresponding v_d value from Section 6.1.2.

6.1.4.1 If v_s is less than or equal to 120 percent of v_d, the results are acceptable (note that in cases where the above calculations have been performed for each sub-run, the results are acceptable if the average percentage for all sub-runs is less than or equal to 120 percent).

6.1.4.2 If v_s is more than 120 percent of v_d, multiply the reported emission rate by the following factor.

$$1 + \frac{(100\ v_s/v_d) - 120}{200}$$

6.2 Average velocity of roof monitor gases. Calculate the average roof monitor velocity using all the velocity or volumetric flow readings from Section 5.1.2.

6.3 Roof monitor temperature. Calculate the mean value of the temperatures recorded in Section 5.2.

6.4 *Concentration of fluorides in roof monitor air* (in mg F/m³).

6.4.1 If a single sampling train was used throughout the run, calculate the average fluoride concentration for the roof monitor using Equation 13A-2 of Method 13A.

6.4.2 If two or more sampling trains were used (i.e., one per sub-run), calculate the average fluoride concentration for the run, as follows:

$$\bar{C}_s = \frac{\sum_{i=1}^{n} (F_t)_i}{\sum_{i=1}^{n} (V_{m(std)})_i} \qquad \text{(Equation 14-2)}$$

Where:

C_s = Average fluoride concentration in roof monitor air, mg F/dscm.

F_t = Total fluoride mass collected during a particular sub-run, mg F (from Equation 13A-1 of Method 13A or Equation 13B-1 of Method 13B).

$V_{m(std)}$ = Total volume of sample gas passing through the dry gas meter during a particular sub-run, dscm (see Equation 5-1 of Method 5).

n = Total number of sub-runs.

6.5 Average volumetric flow from the roof monitor of the potroom(s) (or potroom segment(s)) containing the anemometers is given in Equation 14-3.

$$Q_m = \frac{v_{mt}(A)\,(M_d)\,P_m(293\ K)}{(T_m + 273)\,(760\ mm\ Hg)} \qquad \text{(Equation 14-3)}$$

Where:

Q_m = Average volumetric flow from roof monitor at standard conditions on a dry basis, m³/min.

A = Roof monitor open area, m².

v_{mt} = Average velocity of air in the roof monitor, m/min, from Section 6.2.

P_m = Pressure in the roof monitor; equal to barometric pressure for this application, mm Hg.

T_m = Roof monitor temperature, °C, from Section 6.3.

M_d = Mole fraction of dry gas, which is given by:

$$M_d = (1 - B_{ws})$$

Note.—B_{ws} is the proportion by volume of water vapor in the gas stream, from Equation 5-3, Method 5.

7. *Bibliography.*

1. Shigehara, R. T., A guideline for Evaluating Compliance Test Results (Isokinetic Sampling Rate Criterion). U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, North Carolina, August 1977.

METHOD 15. DETERMINATION OF HYDROGEN SULFIDE, CARBONYL SULFIDE, AND CARBON DISULFIDE EMISSIONS FROM STATIONARY SOURCES[86]

INTRODUCTION

The method described below uses the principle of gas chromatographic separation and flame photometric detection (FPD). Since there are many systems or sets of operating conditions that represent usable methods of determining sulfur emissions, all systems which employ this principle, but differ only in details of equipment and operation, may be used as alternative methods, provided that the criteria set below are met.

1. Principle and applicability

1.1 Principle. A gas sample is extracted from the emission source and diluted with clean dry air. An aliquot of the diluted sample is then analyzed for hydrogen sulfide (H_2S), carbonyl sulfide (COS), and carbon disulfide (CS_2) by gas chromatographic (GC) separation and flame photometric detection (FPD).

1.2 Applicability. This method is applicable for determination of the above sulfur compounds from tail gas control units of sulfur recovery plants.

2. Range and sensitivity

2.1 Range. Coupled with a gas chromtographic system utilizing a 1-milliliter sample size, the maximum limit of the FPD for each sulfur compound is approximately 10 ppm. It may be necessary to dilute gas samples from sulfur recovery plants hundredfold (99:1) resulting in an upper limit of about 1000 ppm for each compound.

2.2 The minimum detectable concentration of the FPD is also dependent on sample size and would be about 0.5 ppm for a 1 ml sample.

3. Interferences

3.1 Moisture Condensation. Moisture condensation in the sample delivery system, the analytical column, or the FPD burner block can cause losses or interferences. This potential is eliminated by heating the sample line, and by conditioning the sample with dry dilution air to lower its dew point below the operating temperature of the GC/FPD analytical system prior to analysis.

3.2 Carbon Monoxide and Carbon Dioxide. CO and CO_2 have substantial desensitizing effects on the flame photometric detector even after 9:1 dilution. (Acceptable systems must demonstrate that they have eliminated this interference by some procedure such as eluding CO and CO_2 before any of the sulfur compounds to be measured.) Compliance with this requirement can be demonstrated by submitting chromatograms of calibration gases with and without CO_2 in the diluent gas. The CO_2 level should be approximately 10 percent for the case with CO_2 present. The two chromatographs should show agreement within the precision limits of section 4.1.

3 3 Elemental Sulfur. The condensation of sulfur vapor in the sampling line can lead to eventual coating and even blockage of the sample line. This problem can be eliminated along with the moisture problem by heating the sample line.

4. Precision

4.1 Calibration Precision. A series of three consecutive injections of the same calibration gas, at any dilution, shall produce results which do not vary by more than ±13 percent from the mean of the three injections.

4.2 Calibration Drift. The calibration drift determined from the mean of three injections made at the beginning and end of any 8-hour period shall not exceed ±5 percent.

5. Apparatus

5.1.1 Probe. The probe must be made of inert material such as stainless steel or glass. It should be designed to incorporate a filter and to allow calibration gas to enter the probe at or near the sample entry point. Any portion of the probe not exposed to the stack gas must be heated to prevent moisture condensation.

5.1.2 The sample line must be made of Teflon,[1] no greater than 1.3 cm (½ in) inside diameter. All parts from the probe to the dilution system must be thermostatically heated to 120° C.

5.1.3 Sample Pump. The sample pump shall be a leakless Teflon coated diaphragm type or equivalent. If the pump is upstream of the dilution system, the pump head must be heated to 120° C.

5.2 Dilution System. The dilution system must be constructed such that all sample contacts are made of inert material (e.g. stainless steel or Teflon). It must be heated to 120° C and be capable of approximately a 9:1 dilution of the sample.

5.3 Gas Chromatograph. The gas chromatograph must have at least the following components:

5.3.1 Oven. Capable of maintaining the separation column at the proper operating temperature ±1° C.

5.3.2 Temperature Gauge. To monitor column oven, detector, and exhaust temperature ±1° C.

5.3.3 Flow System. Gas metering system to measure sample, fuel, combustion gas, and carrier gas flows.

5.3.4 Flame Photometric Detector.

5.3.4.1 Electrometer. Capable of full scale amplification of linear ranges of 10^{-9} to 10^{-4} amperes full scale.

5.3.4.2 Power Supply. Capable of delivering up to 750 volts.

5.3.4.3 Recorder. Compatible with the output voltage range of the electrometer.

5.4 Gas Chromatograph Columns. The column system must be demonstrated to be capable of resolving three major reduced sulfur compounds: H_2S, COS, and CS_2.

To demonstrate that adequate resolution has been achieved the tester must submit a chromatograph of a calibration gas containing all three reduced sulfur compounds in the concentration range of the applicable standard. Adequate resolution will be defined as base line separation of adjacent peaks when the amplifier attenuation is set so that the smaller peak is at least 50 percent of full scale. Base line separation is defined as a return to zero ±5 percent in the interval between peaks. Systems not meeting this criteria may be considered alternate methods subject to the approval of the Administrator.

5.5.1 Calibration System. The calibration system must contain the following components.

5.5.2 Flow System. To measure air flow over permeation tubes at ±2 percent. Each flowmeter shall be calibrated after a complete test series with a wet test meter. If the flow measuring device differs from the wet test meter by 5 percent, the completed test shall be discarded. Alternatively, the tester may elect to use the flow data that would yield the lowest flow measurement. Calibration with a wet test meter before a test is optional.

[1]Mention of trade names or specific products does not constitute an endorsement by the Environmental Protection Agency.

5.5.3 Constant Temperature Bath. Device capable of maintaining the permeation tubes at the calibration temperature within ±1.1° C.

5.5.4 Temperature Gauge. Thermometer or equivalent to monitor bath temperature within ±1° C.

6. Reagents

6.1 Fuel. Hydrogen (H_2) prepurified grade or better.

6.2 Combustion Gas. Oxygen (O_2) or air, research purity or better.

6.3 Carrier Gas. Prepurified grade or better.

6.4 Diluent. Air containing less than 0.5 ppm total sulfur compounds and less than 10 ppm each of moisture and total hydrocarbons.

6.5 Calibration Gases. Permeation tubes, one each of H_2S, COS, and CS_2, gravimetrically calibrated and certified at some convenient operating temperature. These tubes consist of hermetically sealed FEP Teflon tubing in which a liquified gaseous substance is enclosed. The enclosed gas permeates through the tubing wall at a constant rate. When the temperature is constant, calibration gases covering a wide range of known concentrations can be generated by varying and accurately measuring the flow rate of diluent gas passing over the tubes. These calibration gases are used to calibrate the GC/FPD system and the dilution system.

7. Pretest Procedures

The following procedures are optional but would be helpful in preventing any problem which might occur later and invalidate the entire test.

7.1 After the complete measurement system has been set up at the site and deemed to be operational, the following procedures should be completed before sampling is initiated.

7.1.1 Leak Test. Appropriate leak test procedures should be employed to verify the integrity of all components, sample lines, and connections. The following leak test procedure is suggested: For components upstream of the sample pump, attach the probe end of the sample line to a manometer or vacuum gauge, start the pump and pull greater than 50 mm (2 in.) Hg vacuum, close off the pump outlet, and then stop the pump and ascertain that there is no leak for 1 minute. For components after the pump, apply a slight positive pressure and check for leaks by applying a liquid (detergent in water, for example) at each joint. Bubbling indicates the presence of a leak.

7.1.2 System Performance. Since the complete system is calibrated following each test, the precise calibration of each component is not critical. However, these components should be verified to be operating properly. This verification can be performed by observing the response of flowmeters or of the GC output to changes in flow rates or calibration gas concentrations and ascertaining the response to be within predicted limits. If any component or the complete system fails to respond in a normal and predictable manner, the source of the discrepancy should be identifed and corrected before proceeding.

8. Calibration

Prior to any sampling run, calibrate the system using the following procedures. (If more than one run is performed during any 24-hour period, a calibration need not be performed prior to the second and any subsequent runs. The calibration must, however, be verified as prescribed in section 10, after the last run made within the 24-hour

period.)

8.1 General Considerations. This section outlines steps to be followed for use of the GC/FPD and the dilution system. The procedure does not include detailed instructions because the operation of these systems is complex, and it requires an understanding of the individual system being used. Each system should include a written operating manual describing in detail the operating procedures associated with each component in the measurement system. In addition, the operator shuld be familiar with the operating principles of the components; particularly the GC/FPD. The citations in the Bibliography at the end of this method are recommended for review for this purpose.

8.2 Calibration Procedure. Insert the permeation tubes into the tube chamber. Check the bath temperature to assure agreement with the calibration temperature of the tubes within ±0.1°C. Allow 24 hours for the tubes to equilibrate. Alternatively equilibration may be verified by injecting samples of calibration gas at 1-hour intervals. The permeation tubes can be assumed to have reached equilibrium when consecutive hourly samples agree within the precision limits of section 4.1.

Vary the amount of air flowing over the tubes to produce the desired concentrations for calibrating the analytical and dilution systems. The air flow across the tubes must at all times exceed the flow requirement of the analytical systems. The concentration in parts per million generated by a bube containing a specific permeant can be calculated as follows:

$$C = K \times P_r / ML$$

Equation 15-1

where:

C = Concentration of permeant produced in ppm.

P_r = Permeation rate of the tube in μg/min.

M = Molecular weight of the permeant: g/g-mole.

L = Flow rate, l/min, of air over permeant @ 20°C, 760 mm Hg.

K = Gas constant at 20°C and 760 mm Hg = 24.04 l/g mole.

8.3 Calibration of analysis system. Generate a series of three or more known concentrations spanning the linear range of the FPD (approximately 0.05 to 1.0 ppm) for each of the four major sulfur compounds. Bypassing the dilution system, inject these standards in to the GC/FPD analyzers and monitor the responses. Three injects for each concentration must yield the precision described in section 4.1. Failure to attain this precision is an indication of a problem in the calibration or analytical system. Any such problem must be identified and corrected before proceeding.

8.4 Calibration Curves. Plot the GC/FPD response in current (amperes) versus their causative concentrations in ppm on log-log coordinate graph paper for each sulfur compound. Alternatively, a least squares equation may be generated from the calibration data.

8.5 Calibration of Dilution System. Generate a know concentration of hydrogen sulfied using the permeation tube system. Adjust the flow rate of diluent air for the first dilution stage so that the desired level of dilution is approximated. Inject the diluted calibration gas into the GC/FPD system and monitor its response. Three injections for each dilution must yield the precision described in section 4.1. Failure to attain this precision in this step is an indication of a problem in the dilution system. Any such problem must be identified and corrected before proceeding. Using the calibration data for H_2S (developed under 8.3) determine the diluted calibration gas concentration in ppm. Then calculate the dilution factor as the ratio of the calibration gas concentration before dilution to the diluted calibration gas concentration determined under this paragraph. Repeat this procedure for each stage of dilution required. Alternatively, the GC/FPD system may be calibrated by generating a series of three or more concentrations of each sulfur compound and diluting these samples before injecting them into the GC/FPD system. This data will then serve as the calibration data for the unknown samples and a separate determination of the dilution factor will not be necessary. However, the precision requirements of section 4.1 are still applicable.

9. Sampling and Analysis Procedure

9.1 Sampling. Insert the sampling probe into the test port making certain that no dilution air enters the stack through the port. Begin sampling and dilute the sample approximately 9:1 using the dilution system. Note that the precise dilution factor is that which is determined in paragraph 8.5. Condition the entire system with sample for a minimum of 15 minutes prior to commencing analysis.

9.2 Analysis. Aliquots of diluted sample are injected into the GC/FPD analyzer for analysis.

9.2.1 Sample Run. A sample run is composed of 16 individual analyses (injects) performed over a period of not less than 3 hours or more than 6 hours.

9.2.2 Observation for Clogging of Probe. If reductions in sample concentrations are observed during a sample run that cannot be explained by process conditions, the sampling must be interrupted to determine if the sample probe is clogged with particulate matter. If the probe is found to be clogged, the test must be stopped and the results up to that point discarded. Testing may resume after cleaning the probe or replacing it with a clean one. After each run, the sample probe must be inspected and, if necessary, dismantled and cleaned.

10. Post-Test Procedures

10.1 Sample Line Loss. A known concentration of hydrogen sulfide at the level of the applicable standard, ±20 percent, must be introduced into the sampling system at the opening of the probe in sufficient quantities to ensure that there is an excess of sample which must be vented to the atmosphere. The sample must be transported through the entire sampling system to the measurement system in the normal manner. The resulting measured concentration should be compared to the known value to determine the sampling system loss. A sampling system loss of more than 20 percent is unacceptable. Sampling losses of 0-20 percent must be corrected by dividing the resulting sample concentration by the fraction of recovery. The known gas sample may be generated using permeation tubes. Alternatively, cylinders of hydrogen sulfide mixed in air may be used provided they are traceable to permeation tubes. The optional pretest procedures provide a good guideline for determining if there are leaks in the sampling system.

10.2 Recalibration. After each run, or after a series of runs made within a 24-hour period, perform a partial recalibration using the procedures in section 8. Only H_2S (or other permeant) need be used to recalibrate the GC/FPD analysis system (8.3) and the dilution system (8.5).

10.3 Determination of Calibration Drift. Compare the calibration curves obtained prior to the runs, to the calibration curves obtained under paragraph 10.1. The calibration drift should not exceed the limits set forth in paragraph 4.2. If the drift exceeds this limit, the intervening run or runs should be considered not valid. The tester, however, may instead have the option of choosing the calibration data set which would give the highest sample values.

11. Calculations

11.1 Determine the concentrations of each reduced sulfur compound detected directly from the calibration curves. Alternatively, the concentrations may be calculated using the equation for the least squares line.

11.2 Calculation of SO_2 Equivalent. SO_2 equivalent will be determined for each analysis made by summing the concentrations of each reduced sulfur compound resolved during the given analysis.

$$SO_2 \text{ equivalent} = \Sigma(H_2S, COS, 2\,CS_2)d$$

Equation 15-2

where:

SO_2 equivalent = The sum of the concentration of each of the measured compounds (COS, H_2S, CS_2) expressed as sulfur dioxide in ppm.

H_2S = Hydrogen sulfide, ppm.

COS = Carbonyl sulfide, ppm.

CS_2 = Carbon disulfide, ppm.

d = Dilution factor, dimensionless.

11.3 Average SO_2 equivalent will be determined as follows:

$$\text{Average } SO_2 \text{ equivalent} = \frac{\sum_{i=1}^{N} SO_2 \text{ equiv.}_i}{N\,(1 - Bwo)}$$

Equation 15-3

where:

Average SO_2 equivalent$_i$ = Average SO_2 equivalent in ppm, dry basis.

Average SO_2 equivalent$_i$ = SO_2 in ppm as determined by Equation 15-2.

N = Number of analyses performed.

Bwo = Fraction of volume of water vapor in the gas stream as determined by Method 4—Determination of Moisture in Stack Gases (36 FR 24887).

12. Example System

Described below is a system utilized by EPA in gathering NSPS data. This system does not now reflect all the latest developments in equipment and column technology, but it does represent one system that has been demonstrated to work.

12.1 Apparatus.

12.1.1 Sample System.

12.1.1.1 Probe. Stainless steel tubing, 6.35 mm (¼ in.) outside diameter, packed with glass wool.

12.1.1.2 Sample Line. 3/16 inch inside diameter Teflon tubing heated to 120° C. This temperature is controlled by a thermostatic heater.

12.1.1.3 Sample Pump. Leakless Teflon coated diaphragm type or equivalent. The pump head is heated to 120° C by enclosing it in the sample dilution box (12.2.4 below).

12.1.2 Dilution System. A schematic diagram of the dynamic dilution system is given in Figure 15-2. The dilution system is constructed such that all sample contacts are made of inert materials. The dilution

system which is heated to 120° C must be capable of a minimum of 9:1 dilution of sample. Equipment used in the dilution system is listed below:

12.1.2.1 Dilution Pump. Model A-150 Kohmyhr Teflon positive displacement type, nonadjustable 150 cc/min. ±2.0 percent, or equivalent, per dilution stage. A 9:1 dilution of sample is accomplished by combining 150 cc of sample with 1350 cc of clean dry air as shown in Figure 15-2.

12.1.2.2 Valves. Three-way Teflon solenoid or manual type.

12.1.2.3 Tubing. Teflon tubing and fittings are used throughout from the sample probe to the GC/FPD to present an inert surface for sample gas.

12.1.2.4 Box. Insulated box, heated and maintained at 120° C, of sufficient dimensions to house dilution apparatus.

12.1.2.5 Flowmeters. Rotameters or equivalent to measure flow from 0 to 1500 ml/min. ±1 percent per dilution stage.

12.1.3.0 Gas Chromatograph.

12.1.3.1 Column—1.83 m (6 ft.) length of Teflon tubing, 2.16 mm (0.085 in.) inside diameter, packed with deactivated silica gel, or equivalent.

12.1.3.2 Sample Valve. Teflon six port gas sampling valve, equipped with a 1 ml sample loop, actuated by compressed air (Figure 15-1).

12.1.3.3 Oven. For containing sample valve, stripper column and separation column. The oven should be capable of maintaining an elevated temperature ranging from ambient to 100° C, constant within ±1° C.

12.1.3.4 Temperature Monitor. Thermocouple pyrometer to measure column oven, detector, and exhaust temperature ±1° C.

12.1.3.5 Flow System. Gas metering system to measure sample flow, hydrogen flow, oxygen flow and nitrogen carrier gas flow.

12.1.3.6 Detector. Flame photometric detector.

12.1.3.7 Electrometer. Capable of full scale amplification of linear ranges of 10^{-9} to 10^{-4} amperes full scale.

12.1.3.8 Power Supply. Capable of delivering up to 750 volts.

12.1.3.9 Recorder. Compatible with the output voltage range of the electrometer.

12.1.4 Calibration. Permeation tube system (Figure 15-3).

12.1.4.1 Tube Chamber. Glass chamber of sufficient dimensions to house permeation tubes.

12.1.4.2 Mass Flowmeters. Two mass flowmeters in the range 0-3 l/min. and 0-10 l/min. to measure air flow over permeation tubes at ±2 percent. These flowmeters shall be cross-calibrated at the beginning of each test. Using a convenient flow rate in the measuring range of both flowmeters, set and monitor the flow rate of gas over the permeation tubes. Injection of calibration gas generated at this flow rate as measured by one flowmeter followed by injection of calibration gas at the same flow rate as measured by the other flowmeter should agree within the specified precision limits. If they do not, then there is a problem with the mass flow measurement. Each mass flowmeter shall be calibrated prior to the first test with a wet test meter and thereafter at least once each year.

12.1.4.3 Constant Temperature Bath. Capable of maintaining permeation tubes at certification temperature of 30° C within ±0.1° C.

12.2 Reagents.

12.2.1 Fuel. Hydrogen (H_2) prepurified grade or better.

12.2.2 Combustion Gas. Oxygen (O_2) research purity or better.

12.2.3 Carrier Gas. Nitrogen (N_2) prepurified grade or better.

12.2.4 Diluent. Air containing less than 0.5 ppm total sulfur compounds and less than 10 ppm each of moisture and total hydrocarbons, and filtered using MSA filters 46727 and 79030, or equivalent. Removal of sulfur compounds can be verified by injecting dilution air only, described in section 8.3.

12.2.5 Compressed Air. 60 psig for GC valve actuation.

12.2.6 Calibration Gases. Permeation tubes gravimetrically calibrated and certified at 30.0° C.

12.3 Operating Parameters. The operating parameters for the GC/FPD system are as follows: nitrogen carrier gas flow rate of 100 cc/min, exhaust temperature of 110° C, detector temperature 105° C, oven temperature of 40° C, hydrogen flow rate of 80 cc/minute, oxygen flow rate of 20 cc/minute, and sample flow rate of 80 cc/minute.

12.4 Analysis. The sample valve is actuated for 1 minute in which time an aliquot of diluted sample is injected onto the separation column. The valve is then deactivated for the remainder of analysis cycle in which time the sample loop is refilled and the separation column continues to be foreflushed. The elution time for each compound will be determined during calibration.

13. Bibliography

13.1 O'Keeffe, A. E. and G. C. Ortman. "Primary Standards for Trace Gas Analysis." Anal. Chem. 38,760 (1966).

13.2 Stevens, R. K., A. E. O'Keeffe, and G. C. Ortman. "Absolute Calibration of a Flame Photometric Detector to Volatile Sulfur Compounds at Sub-Part-Per-Million Levels." Environmental Science and Technology 3:7 (July, 1969).

13.3 Mulick, J. D., R. K. Stevens, and R. Baumgardner. "An Analytical System Designed to Measure Multiple Malodorous Compounds Related to Kraft Mill Activities." Presented at the 12th Conference on Methods in Air Pollution and Industrial Hygiene Studies, University of Southern California, Los Angeles, Calif. April 6-8, 1971.

13.4 Devonald, R. H., R. S. Serenius, and A. D. McIntyre. "Evaluation of the Flame Photometric Detector for Analysis of Sulfur Compounds." Pulp and Paper Magazine of Canada, 73,3 (March, 1972).

13.5 Grimley, K. W., W. S. Smith, and R. M. Martin. "The Use of a Dynamic Dilution System in the Conditioning of Stack Gases for Automated Analysis by a Mobile Sampling Van." Presented at the 63rd Annual APCA Meeting in St. Louis, Mo. June 14-19, 1970.

13.6 General Reference. Standard Methods of Chemical Analysis Volume III A and B Instrumental Methods. Sixth Edition. Van Nostrand Reinhold Co.

METHOD 16. SEMICONTINUOUS DETERMINATION OF SULFUR EMISSIONS FROM STATIONARY SOURCES [82]

Introduction

The method described below uses the principle of gas chromatographic separation and flame photometric detection. Since there are many systems or sets of operating conditions that represent usable methods of determining sulfur emissions, all systems which employ this principle, but differ only in details of equipment and operation, may be used as alternative methods, provided that the criteria set below are met.

1. *Principle and Applicability.*

1.1 Principle. A gas sample is extracted from the emission source and diluted with clean dry air. An aliquot of the diluted sample is then analyzed for hydrogen sulfide (H_2S), methyl mercaptan (MeSH), dimethyl sulfide (DMS) and dimethyl disulfide (DMDS) by gas chromatographic (GC) separation and flame photometric detection (FPD). These four compounds are known collectively as total reduced sulfur (TRS).

1.2 Applicability. This method is applicable for determination of TRS compounds from recovery furnaces, lime kilns, and smelt dissolving tanks at kraft pulp mills.

2. *Range and Sensitivity.*

2.1 Range. Coupled with a gas chromatographic system utilizing a ten milliliter sample size, the maximum limit of the FPD for each sulfur compound is approximately 1 ppm. This limit is expanded by dilution of the sample gas before analysis. Kraft mill gas samples are normally diluted tenfold (9:1), resulting in an upper limit of about 10 ppm for each compound.

For sources with emission levels between 10 and 100 ppm, the measuring range can be best extended by reducing the sample size to 1 milliliter.

2.2 Using the sample size, the minimum detectable concentration is approximately 50 ppb.

3. *Interferences.*

3.1 Moisture Condensation. Moisture condensation in the sample delivery system, the analytical column, or the FPD burner block can cause losses or interferences. This potential is eliminated by heating the sample line, and by conditioning the sample with dry dilution air to lower its dew point below the operating temperature of the GC/FPD analytical system prior to analysis.

3.2 Carbon Monoxide and Carbon Dioxide. CO and CO_2 have substantial desensitizing effect on the flame photometric detector even after 9:1 dilution. Acceptable systems must demonstrate that they have eliminated this interference by some procedure such as eluting these compounds before any of the compounds to be measured. Compliance with this requirement can be demonstrated by submitting chromatograms of calibration gases with and without CO_2 in the diluent gas. The CO_2 level should be approximately 10 percent for the case with CO_2 present. The two chromatographs should show agreement within the precision limits of Section 4.1.

3.3 Particulate Matter. Particulate matter in gas samples can cause interference by eventual clogging of the analytical system. This interference must be eliminated by use of a probe filter.

3.4 Sulfur Dioxide. SO_2 is not a specific interferent but may be present in such large amounts that it cannot be effectively separated from other compounds of interest. The procedure must be designed to eliminate this problem either by the choice of separation columns or by removal of SO_2 from the sample. In the example system, SO_2 is removed by a citrate buffer solution prior to GC injection. This scrubber will be used when SO_2 levels are high enough to prevent baseline separation from the reduced sulfur compounds. [93]

Compliance with this section can be demonstrated by submitting chromatographs of calibration gases with SO_2 present in the same quantities expected from the emission source to be tested. Acceptable systems shall show baseline separation with the amplifier attenuation set so that the reduced sulfur compound of concern is at least 50 percent of full scale. Base line separation is defined as a return to zero ± percent in the interval between peaks.

4. *Precision and Accuracy.*

4.1 GC/FPD and Dilution System Calibration Precision. A series of three consecutive injections of the same calibration gas, at any dilution, shall produce results which do not vary by more than ±5 percent from the mean of the three injections.[93]

4.2 GC/FPD and Dilution System Calibration Drift. The calibration drift determined from the mean of three injections made at the beginning and end of any 8-hour period shall not exceed ± percent.

4.3 System Calibration Accuracy. Losses through the sample transport system must be measured and a correction factor developed to adjust the calibration accuracy to 100 percent.[93]

5. *Apparatus* (See Figure 16-1).

5.1. Sampling.[93]

5.1.1 Probe. The probe must be made of inert material such as stainless steel or glass. It should be designed to incorporate a filter and to allow calibration gas to enter the probe at or near the sample entry point. Any portion of the probe not exposed to the stack gas must be heated to prevent moisture condensation.

5.1.2 Sample Line. The sample line must be made of Teflon,[1] no greater than 1.3 cm (½) inside diameter. All parts from the probe to the dilution system must be thermostatically heated to 120° C.

5.1.3 Sample Pump. The sample pump shall be a leakless Teflon-coated diaphragm type or equivalent. If the pump is upstream of the dilution system, the pump head must be heated to 120° C.

5.2 Dilution System. The dilution system must be constructed such that all sample contacts are made of inert materials (e.g., stainless steel or Teflon). It must be heated to 120° C. and be capable of approximately a 9:1 dilution of the sample.

5.3 SO_2 Scrubber. The SO_2 scrubber is a midget impinger packed with glass wool to eliminate entrained mist and charged with potassium citrate-citric acid buffer.[93]

5.4 Gas Chromatograph. The gas chromatograph must have at least the following components: [93]

5.4.1 Oven. Capable of maintaining the separation column at the proper operating temperature ±1° C.[93]

5.4.2 Temperature Gauge. To monitor column oven, detector, and exhaust temperature ±1° C.[93]

5.4.3 Flow System. Gas metering system to measure sample, fuel, combustion gas, and carrier gas flows. [93]

5.4.4 Flame Photometric Detector.[93]

5.4.4.1 Electrometer. Capable of full scale amplification of linear ranges of 10^{-9} to 10^{-4} amperes full scale.[93]

5.4.4.2 Power Supply. Capable of delivering up to 750 volts.[93]

5.4.4.3 Recorder. Compatible with the output voltage range of the electrometer.[93]

5.5 Gas Chromatograph Columns. The column system must be demonstrated to be capble of resolving the four major reduced sulfur compounds: H_2S, MeSH, DMS, and DMDS. It must also demonstrate freedom from known interferences.[93]

To demonstrate that adequate resolution has been achieved, the tester must submit a chromatograph of a calibration gas containing all four of the TRS compounds in the concentration range of the applicable standard. Adequate resolution will be defined as base line separation of adjacent peaks when the amplifier attenuation is set so that the smaller peak is at least 50 percent of full scale. Base line separation is defined in Section 3.4. Systems not meeting this criteria may be considered alternate methods subject to the approval of the Administrator.[93]

5.5.1 Calibration System. The calibration system must contain the following components.[93]

5.5.2 Tube Chamber. Chamber of glass or Teflon of sufficient dimensions to house permeation tubes.[93]

5.5.3 Flow System. To measure air flow over permeation tubes at ±2 percent. Each flowmeter shall be calibrated after a complete test series with a wet test meter. If the flow measuring device differs from the wet test meter by 5 percent, the completed test shall be discarded. Alternatively, the tester may elect to use the flow data that would yield the lower flow measurement. Calibration with a wet test meter before a test is optional.[93]

5.5.4 Constant Temperature Bath. Device capable of maintaining the permeation tubes at the calibration temperature within ±0.1° C.[93]

5.5.5 Temperature Gauge. Thermometer or equivalent to monitor bath temperature within ±1° C.[93]

6. *Reagents.*

6.1 Fuel. Hydrogen (H_2) prepurified grade or better.

6.2 Combustion Gas. Oxygen (O_2) or air, research purity or better.

6.3 Carrier Gas. Prepurified grade or better.

6.4 Diluent. Air containing less than 50 ppb total sulfur compounds and less than 10 ppm each of moisture and total hydrocarbons. This gas must be heated prior to mixing with the sample to avoid water condensation at the point of contact.

6.5 Calibration Gases. Permeation tubes, one each of H_2S, MeSH, DMS, and DMDS, agravimetrically calibrated and certified at some convenient operating temperature. These tubes consist of hermetically sealed FEP Teflon tubing in which a liquified gaseous substance is enclosed. The enclosed gas permeates through the tubing wall at a constant rate. When the temperature is constant, calibration gases covering a wide range of known concentrations can be generated by varying and accurately measuring the flow rate of diluent gas passing over the tubes. These calibration gases are used to calibrate the GC/FPD system and the dilution system.

6.6 Citrate Buffer. Dissolve 300 grams of potassium citrate and 41 grams of anhydrous citric acid in 1 liter of deionized water. 284 grams of sodium citrate may be substituted for the potassium citrate. [93]

[1] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

7. *Pretest Procedures.* The following procedures are optional but would be helpful in preventing any problem which might occur later and invalidate the entire test.

7.1 After the complete measurement system has been set up at the site and deemed to be operational, the following procedures should be completed before sampling is initiated.

7.1.1 Leak Test. Appropriate leak test procedures should be employed to verify the integrity of all components, sample lines, and connections. The following leak test procedure is suggested: For components upstream of the sample pump, attach the probe end of the sample line to a manometer or vacuum gauge, start the pump and pull greater than 50 mm (2 in.) Hg vacuum, close off the pump outlet, and then stop the pump and ascertain that there is no leak for 1 minute. For components after the pump, apply a slight positive pressure and check for leaks by applying a liquid (detergent in water, for example) at each joint. Bubbling indicates the presence of a leak.

7.1.2 System Performance. Since the complete system is calibrated following each test, the precise calibration of each component is not critical. However, these components should be verified to be operating properly. This verification can be performed by observing the response of flowmeters or of the GC output to changes in flow rates or calibration gas concentrations and ascertaining the response to be within predicted limits. In any component, or if the complete system fails to respond in a normal and predictable manner, the source of the discrepancy should be identified and corrected before proceeding.

8. *Calibration.* Prior to any sampling run, calibrate the system using the following procedures. (If more than one run is performed during any 24-hour period, a calibration need not be performed prior to the second and any subsequent runs. The calibration must, however, be verified as prescribed in Section 10, after the last run made within the 24-hour period.)

8.1 General Considerations. This section outlines steps to be followed for use of the GC/FPD and the dilution system. The procedure does not include detailed instructions because the operation of these systems is complex, and it requires a understanding of the individual system being used. Each system should include a written operating manual describing in detail the operating procedures associated with each component in the measurement system. In addition, the operator should be familiar with the operating principles of the components; particularly the GC/FPD. The citations in the Bibliography at the end of this method are recommended for review for this purpose.

8.2 Calibration Procedure. Insert the permeation tubes into the tube chamber. Check the bath temperature to assure agreement with the calibration temperature of the tubes within ±0.1° C. Allow 24 hours for the tubes to equilibrate. Alternatively equilibration may be verified by injecting samples of calibration gas at 1-hour intervals. The permeation tubes can be assumed to have reached equilibrium when consecutive hourly samples agree within the precision limits of Section 4.1.

Vary the amount of air flowing over the tubes to produce the desired concentrations for calibrating the analytical and dilution systems. The air flow across the tubes must at all times exceed the flow requirement of the analytical systems. The concentration in parts per million generated by a tube containing a specific permeant can be calculated as follows:

$$C = K \frac{P_r}{ML}$$

Equation 16-1

where:

C=Concentration of permeant produced in ppm.

P_r=Permeation rate of the tube in μg/min.

M=Molecular weight of the permeant (g/g-mole).

L=Flow rate, 1/min, of air over permeant @ 20° C, 760 mm Hg.

K=Gas constant at 20° C and 760 mm Hg=24.04 1/g mole.

8.3 Calibration of analysis system. Generate a series of three or more known concentrations spanning the linear range of the FPD (approximately 0.05 to 1.0 ppm) for each of the four major sulfur compounds. Bypassing the dilution system, but using the SO_2 scrubber, inject these standards into the GC/FPD analyzers and monitor the responses. Three injects for each concentration must yield the precision described in Section 4.1. Failure to attain this precision is an indication of a problem in the calibration or analytical system. Any such problem must be identified and corrected before proceeding.[93]

8.4 Calibration Curves. Plot the GC/FPD response in current (amperes) versus their causative concentrations in ppm on log-log coordinate graph paper for each sulfur compound. Alternatively, a least squares equation may be generated from the calibration data.

8.5 Calibration of Dilution System. Generate a known concentration of hydrogen sulfide using the permeation tube system. Adjust the flow rate of diluent air for the first dilution stage so that the desired level of dilution is approximated. Inject the diluted calibration gas into the GC/FPD system and monitor its response. Three injections for each dilution must yield the precision described in Section 4.1. Failure to attain this precision in this step is an indication of a problem in the dilution system. Any such problem must be identified and corrected before proceeding. Using the calibration data for H_2S (developed under 8.3) determine the diluted calibration gas concentration in ppm. Then calculate the dilution factor as the ratio of the calibration gas concentration before dilution to the diluted calibration gas concentration determined under this paragraph. Repeat this procedure for each stage of dilution required. Alternatively, the GC/FPD system may be calibrated by generating a series of three or more concentrations of each sulfur compound and diluting these samples before injecting them into the GC/FPD system. This data will then serve as the calibration data for the unknown samples and a separate determination of the dilution factor will not be necessary. However, the precision requirements of Section 4.1 are still applicable.

9. *Sampling and Analysis Procedure.*

9.1 Sampling. Insert the sampling probe into the test port making certain that no dilution air enters the stack through the port. Begin sampling and dilute the sample approximtely 9:1 using the dilution system. Note that the precise dilution factor is that which is determined in paragraph 8.5. Condition the entire system with sample for a minimum of 15 minutes prior to commencing analysis.

9.2 Analysis. Aliquots of diluted sample pass through the SO_2 scrubber, and then are injected into the GC/FPD analyzer for analysis.[93]

9.2.1 Sample Run. A sample run is composed of 16 individual analyses (injects) performed over a period of not less than 3 hours or more than 6 hours.

9.2.2 Observation for Clogging of Probe If reductions in sample concentrations are observed during a sample run that cannot be explained by process conditions, the sampling must be interrupted to determine if the sample probe is clogged with particulate matter. If the probe is found to be clogged, the test must be stopped and the results up to that point discarded. Testing may resume after cleaning the probe or replacing it with a clean one. After each run, the sample probe must be inspected and, if necessary, dismantled and cleaned.

10. *Post-Test Procedures.*

10.1 Sample line loss. A known concentration of hydrogen sulfide at the level of the applicable standard, ± 20 percent, must be introduced into the sampling system in sufficient quantities to insure that there is an excess of sample which must be vented to the atmosphere. The sample must be introduced immediately after the probe and filter and transported through the remainder of the sampling system to the measurement system in the normal manner. The resulting measured concentration should be compared to the known value to determine the sampling system loss.[91]

For sampling losses greater than 20 percent in a sample run, the sample run is not to be used when determining the arithmetic mean of the performance test. For sampling losses of 0-20 percent, the sample concentration must be corrected by dividing the sample concentration by the fraction of recovery. The fraction of recovery is equal to one minus the ratio of the measured concentration to the known concentration of hydrogen sulfide in the sample line loss procedure. The known gas sample may be generated using permeation tubes. Alternatively, cylinders of hydrogen sulfide mixed in air may be used provided they are traceable to permeation tubes. The optional pretest procedures provide a good guideline for determining if there are leaks in the sampling system.[91]

10.2 Recalibration. After each run, or after a series of runs made within a 24-hour period, perform a partial recalibration using the procedures in Section 8. Only H_2S (or other permeant) need be used to recalibrate the GC/FPD analysis system (8.3) and the dilution system (8.5).

10.3 Determination of Calibration Drift. Compare the calibration curves obtained prior to the runs, to the calibration curves obtained under paragraph 10.1. The calibration drift should not exceed the limits set forth in subsection 4.2. If the drift exceeds this limit, the intervening run or runs should be considered not valid. The tester, however, may instead have the option of choosing the calibration data set which would give the highest sample values.[93]

11. *Calculations.*

11.1 Determine the concentrations of each reduced sulfur compound detected directly from the calibration curves. Alternatively, the concentrations may be calculated using the equation for the least square line.

11.2 Calculation of TRS. Total reduced sulfur will be determined for each anaylsis made by summing the concentrations of each reduced sulfur compound resolved during a given analysis.

$$TRS = \Sigma (H_2S, MeSH, DMS, 2DMDS)d$$

Equation 16 2

where:

TRS = Total reduced sulfur in ppm, wet basis.
H_2S = Hydrogen sulfide, ppm.
MeSH = Methyl mercaptan, ppm.
DMS = Dimethyl sulfide, ppm.
DMDS = Dimethyl disulfide, ppm.
d = Dilution factor, dimensionless.

11.3 Average TRS. The average TRS will be determined as follows:

$$\text{Average TRS} = \frac{\sum_{i=1}^{N} TRS_i}{N(1-B_{wo})}$$

Average TRS = Average total reduced sulfur in ppm, dry basis.
TRS_i = Total reduced sulfur in ppm as determined by Equation 16-2.
N = Number of samples.
B_{wo} = Fraction of volume of water vapor in the gas stream as determined by Reference method 4—Determination of 93 Moisture in Stack Gases (36 FR 24887).

11.4 Average concentration of individual reduced sulfur compounds.

$$C = \frac{\sum_{i=1}^{N} S_i}{N}$$

Equation 16-3

where:

S_i = Concentration of any reduced sulfur compound from the ith sample injection, ppm.
C = Average concentration of any one of the reduced sulfur compounds for the entire run, ppm.
N = Number of injections in any run period.

12. *Example System.* Described below is a system utilized by EPA in gathering NSPS data. This system does not now reflect all the latest developments in equipment and column technology, but it does represent one system that has been demonstrated to work.

12.1 Apparatus.

12.1.1 Sampling System.

12.1.1.1 Probe. Figure 16-1 illustrates the probe used in lime kilns and other sources where significant amounts of particulate matter are present. the probe is designed with the deflector shield placed between the sample and the gas inlet holes and the glass wool plugs to reduce clogging of the filter and possible adsorption of sample gas. The exposed portion of the probe between the sampling port and the sample line is heated with heating tape.

12.1.1.2 Sample Line 3/8 inch inside diameter Teflon tubing, heated to 120° C. This temperature is controlled by a thermostatic heater.

12.1.1.3 Sample Pump. Leakless Teflon coated diaphragm type or equivalent. The pump head is heated to 120° C by enclosing it in the sample dilution box (12.1.2.4 below).

12.1.2 Dilution System. A schematic diagram of the dynamic dilution system is given in Figure 16-2. The dilution system is constructed such that all sample contacts are made of inert materials. The dilution system which is heated to 120° C must be capable of a minimum of 9:1 dilution of sample. Equipment used in the dilution system is listed below: 93

12.1.2.1 Dilution Pump. Model A-150 Kohmyhr Teflon positive displacement type, nonadjustable 150 cc/min. ±2.0 percent, or equivalent, per dilution stage. A 9:1 dilution of sample is accomplished by combining 150 cc of sample with 1,350 cc of clean dry air as shown in Figure 16-2.

12.1.2.2 Valves. Three-way Teflon solenoid or manual type.

12.1.2.3 Tubing. Teflon tubing and fittings are used throughout from the sample probe to the GC/FPD to present an inert surface for sample gas.

12.1.2.4 Box. Insulated box, heated and maintained at 120° C, of sufficient dimensions to house dilution apparatus.

12.1.2.5 Flowmeters. Rotameters or equivalent to measure flow from 0 to 1500 ml/min ±1 percent per dilution stage.

12.1.3 SO_2 Scrubber. Midget impinger with 15 ml of potassium citrate buffer to absorb SO_2 in the sample. 93

12.1.4 Gas Chromatograph Columns Two types of columns are used for separation of low and high molecular weight sulfur compounds: 93

12.1.4.1 Low Molecular Weight Sulfur Compounds Column GC/FPD-I. 93

12.1.4.1.1 Separation Column. 11 m by 2.16 mm (36 ft by 0.085 in) inside diameter Teflon tubing packed with 30/60 mesh Teflon coated with 5 percent polyphenyl ether and 0.05 percent orthophosphoric acid, or equivalent (see Figure 16-3).

12.1.4.1.2 Stripper or Precolumn. 0.6 m by 2.16 mm (2 ft by 0.085 in) inside diameter Teflon tubing. 93

12.1.4.1.3 Sample Valve. Teflon 10-port gas sampling valve, equipped with a 10 ml sample loop, actuated by compressed air (Figure 16-3). 93

12.1.4.1.4 Oven. For containing sample valve, stripper column and separation column. The oven should be capable of maintaining an elevated temperature ranging from ambient to 100° C, constant within ±1° C. 93

12.1.4.1.5 Temperature Monitor. Thermocouple pyrometer to measure column oven, detector, and exhaust temperature ±1° C. 93

12.1.4.1.6 Flow System. Gas metering system to measure sample flow, hydrogen flow, and oxygen flow (and nitrogen carrier gas flow). 93

12.1.4.1.7 Detector. Flame photometric detector. 93

12.1.4.1.8 Electrometer. Capable of full scale amplification of linear ranges of 10^{-9} to 10^{-4} amperes full scale. 93

12.1.4.1.9 Power Supply. Capable of delivering up to 750 volts. 93

12.1.4.1.10 Recorder. Compatible with the output voltage range of the electrometer. 93

12.1.4.2 High Molecular Weight Compounds Column (GC/FPD-II). 93

12.1.4.2.1. Separation Column. 3.05 m by 2.16 mm (10 ft by 0.0885 in) inside diameter Teflon tubing packed with 30/60 mesh Teflon coated with 10 percent Triton X-305, or equivalent. 93

12.1.4.2.2 Sample Valve. Teflon 6-port gas sampling valve equipped with a 10 ml sample loop, actuated by compressed air (Figure 16-3). 93

12.1.4.2.3 Other Components. All components same as in 12.1.4.1.5 to 12.1.4.1.10.

12.1.5 Calibration. Permeation tube system (figure 16-4). 93

12.1.5.1 Tube Chamber. Glass chamber of sufficient dimensions to house permeation tubes. 93

12.1.5.2 Mass Flowmeters. Two mass flowmeters in the range 0-3 l/min. and 0-10 l/min. to measure air flow over permeation tubes at ±2 percent. These flowmeters shall be cross-calibrated at the beginning of each test. Using a convenient flow rate in the measuring range of both flowmeters, set and monitor the flow rate of gas over the permeation tubes. Injection of calibration gas generated at this flow rate as measured by one flowmeter followed by injection of calibration gas at the same flow rate as measured by the other flowmeter should agree within the specified precision limits. If they do not, then there is a problem with the mass flow measurement. Each mass flowmeter shall be calibrated prior to the first test with a wet test meter and thereafter, at least once each year.

12.1.5.3 Constant Temperature Bath. Capable of maintaining permeation tubes at certification temperature of 30° C. within ±0.1° C.

12.2 Reagents

12.2.1 Fuel. Hydrogen (H_2) prepurified grade or better.

12.2.2. Combustion Gas. Oxygen (O_2) research purity or better.

12.2.3 Carrier Gas. Nitrogen (N_2) prepurified grade or better.

12.2.4 Diluent. Air containing less than 50 ppb total sulfur compounds and less than 10 ppm each of moisture and total hydrocarbons, and filtered using MSA filters 46727 and 79030, or equivalent. Removal of sulfur compounds can be verified by injecting dilution air only, described in Section 8.3.

12.2.5 Compressed Air. 60 psig for GC valve actuation.

12.2.6 Calibrated Gases. Permeation tubes gravimetrically calibrated and certified at 30.0° C.

12.2.7 Citrate Buffer. Dissolve 300 grams of potassium citrate and 41 grams of anhydrous citric acid in 1 liter of deionized water. 284 grams of sodium citrate may be substituted for the potassium citrate. 93

12.3 Operating Parameters.

12.3.1 Low-Molecular Weight Sulfur Compounds. The operating parameters for the GC/FPD system used for low molecular weight compounds are as follows: nitrogen carrier gas flow rate of 50 cc/min, exhaust temperature of 110° C, detector temperature of 105° C, oven temperature of 40° C, hydrogen flow rate of 80 cc/min, oxygen flow rate of 20 cc/min, and sample flow rate between 20 and 80 cc/min.

12.3.2 High-Molecular Weight Sulfur Compounds. The operating parameters for the GC/FPD system for high molecular weight compounds are the same as in 12.3.1 except: oven temperature of 70° C, and nitrogen carrier gas flow of 100 cc/min.

12.4 Analysis Procedure.

12.4.1 Analysis. Aliquots of diluted sample are injected simultaneously into both GC/FPD analyzers for analysis. GC/FPD-I is used to measure the low-molecular weight reduced sulfur compounds. The low molecular weight compounds include hydrogen sulfide, methyl mercaptan, and dimethyl sulfide. GC/FPD-II is used to resolve the high-molecular weight compound. The high-molecular weight compound is dimethyl disulfide.

12.4.1.1 Analysis of Low-Molecular Weight Sulfur Compounds. The sample valve is actuated for 3 minutes in which time an aliquot of diluted sample is injected into the stripper column and analytical column. The valve is then deactivated for approximately 12 minutes in which time, the analytical column continues to be fore-

flushed, the stripper column is backflushed, and the sample loop is refilled. Monitor the responses. The elution time for each compound will be determined during calibration.

12.4.1.2 Analysis of High-Molecular Weight Sulfur Compounds. The procedure is essentially the same as above except that no stripper column is needed.

13. *Bibliography.*

13.1 O'Keeffe, A. E. and G. C. Ortman. "Primary Standards for Trace Gas Analysis." Analytical Chemical Journal, 38,760 (1966).

13.2 Stevens, R. K., A. E. O'Keeffe, and G. C. Ortman. "Absolute Calibration of a Flame Photometric Detector to Volatile Sulfur Compounds at Sub-Part-Per-Million Levels." Environmental Science and Technology, 3:7 (July, 1969).

13.3 Mulick, J. D., R. K. Stevens, and R. Baumgardner. "An Analytical System Designed to Measure Multiple Malodorous Compounds Related to Kraft Mill Activities." Presented at the 12th Conference on Methods in Air Pollution and Industrial Hygiene Studies, University of Southern California, Los Angeles, CA. April 6-8, 1971.

13.4 Devonald, R. H., R. S. Serenius, and A. D. McIntyre. "Evaluation of the Flame Photometric Detector for Analysis of Sulfur Compounds." Pulp and Paper Magazine of Canada, 73,3 (March, 1972).

13.5 Grimley, K. W., W. S. Smith, and R. M. Martin. "The Use of a Dynamic Dilution System in the Conditioning of Stack Gases for Automated Analysis by a Mobile Sampling Van." Presented at the 63rd Annual APCA Meeting in St. Louis, Mo. June 14-19, 1970.

13.6 *General Reference.* Standard Methods of Chemical Analysis Volume III A and B Instrumental Methods. Sixth Edition. Van Nostrand Reinhold Co 93

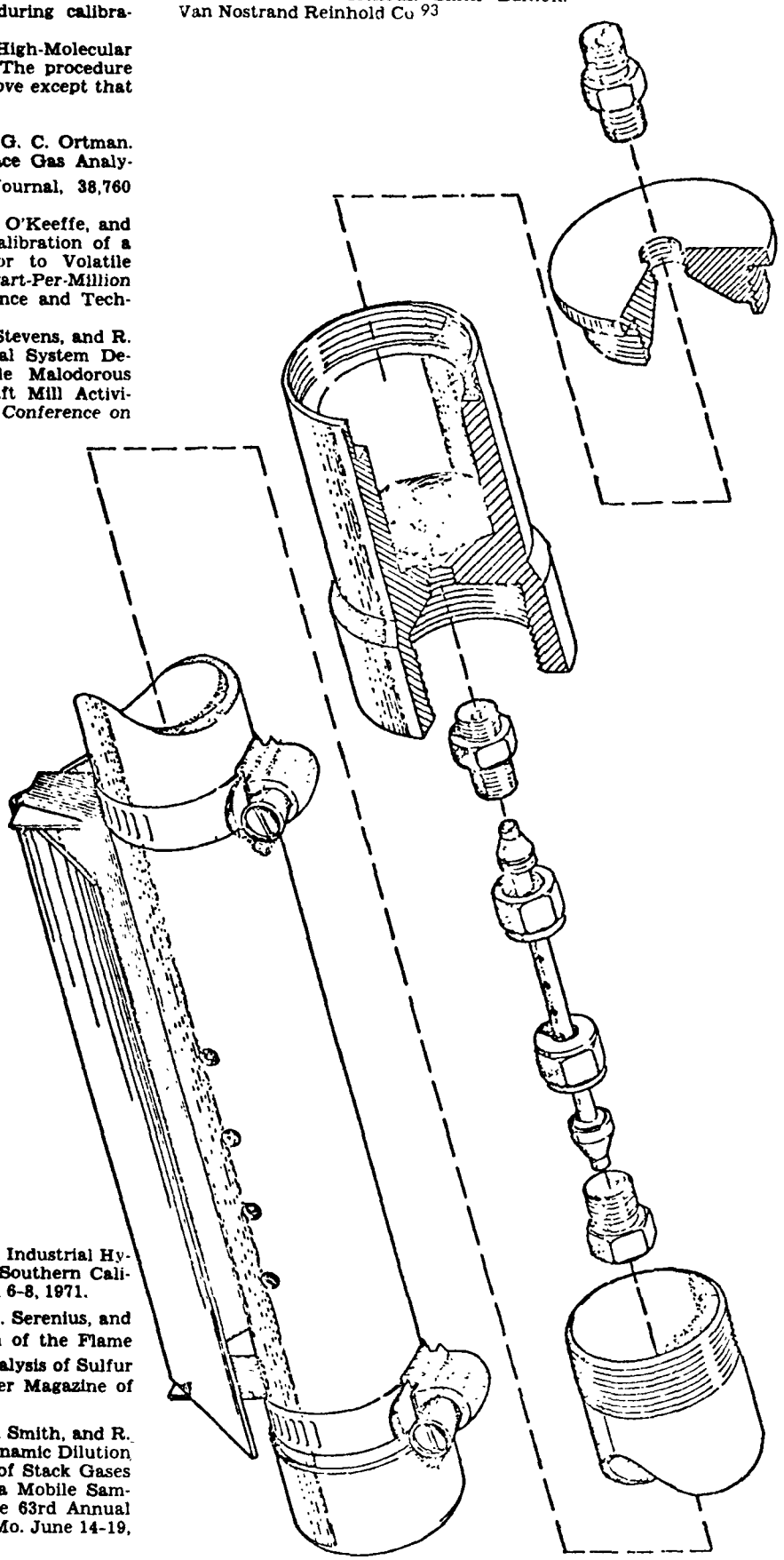


Figure 16-1. Probe used for sample gas containing high particulate loadings.

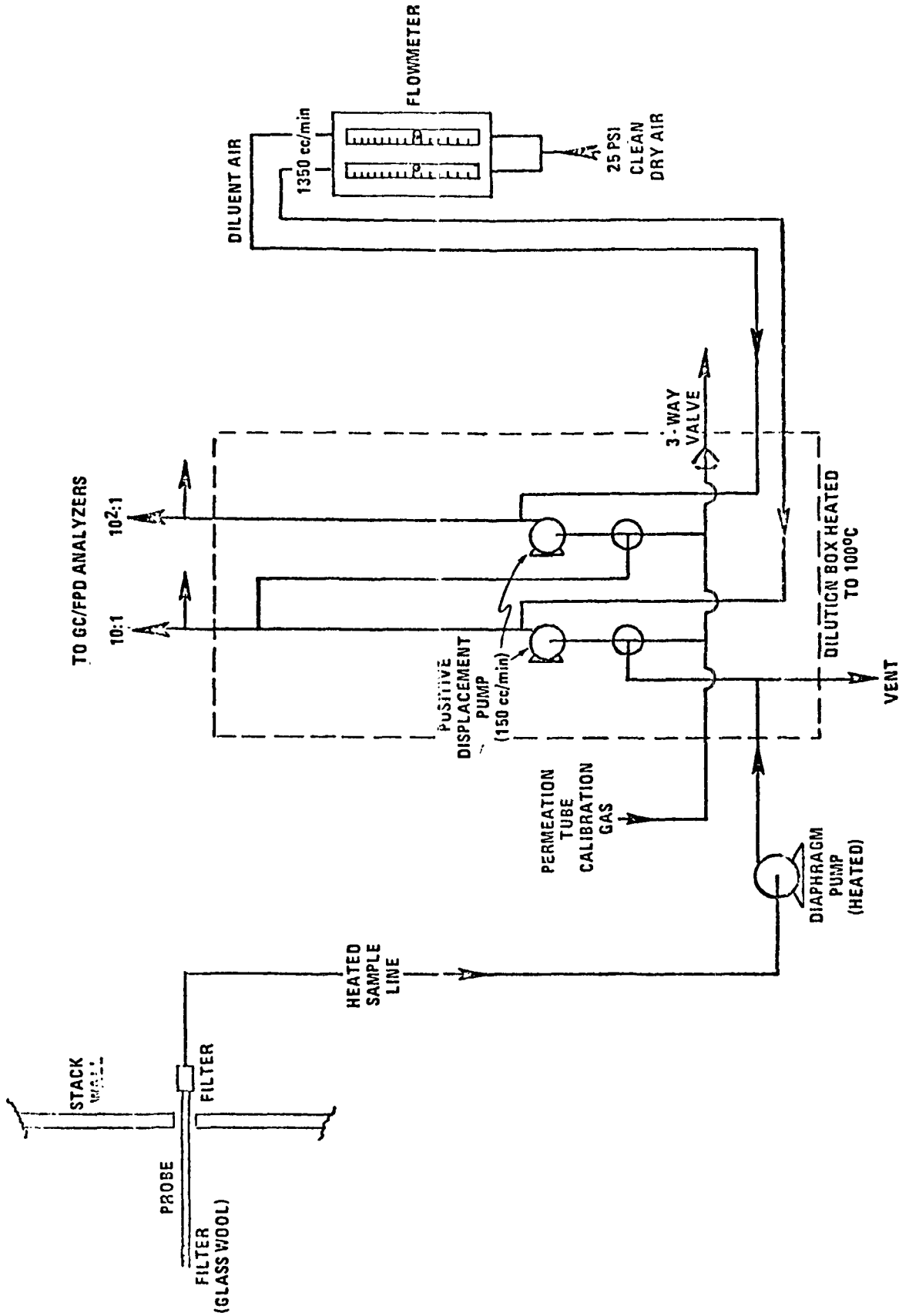


Figure 16-2. Sampling and dilution apparatus.

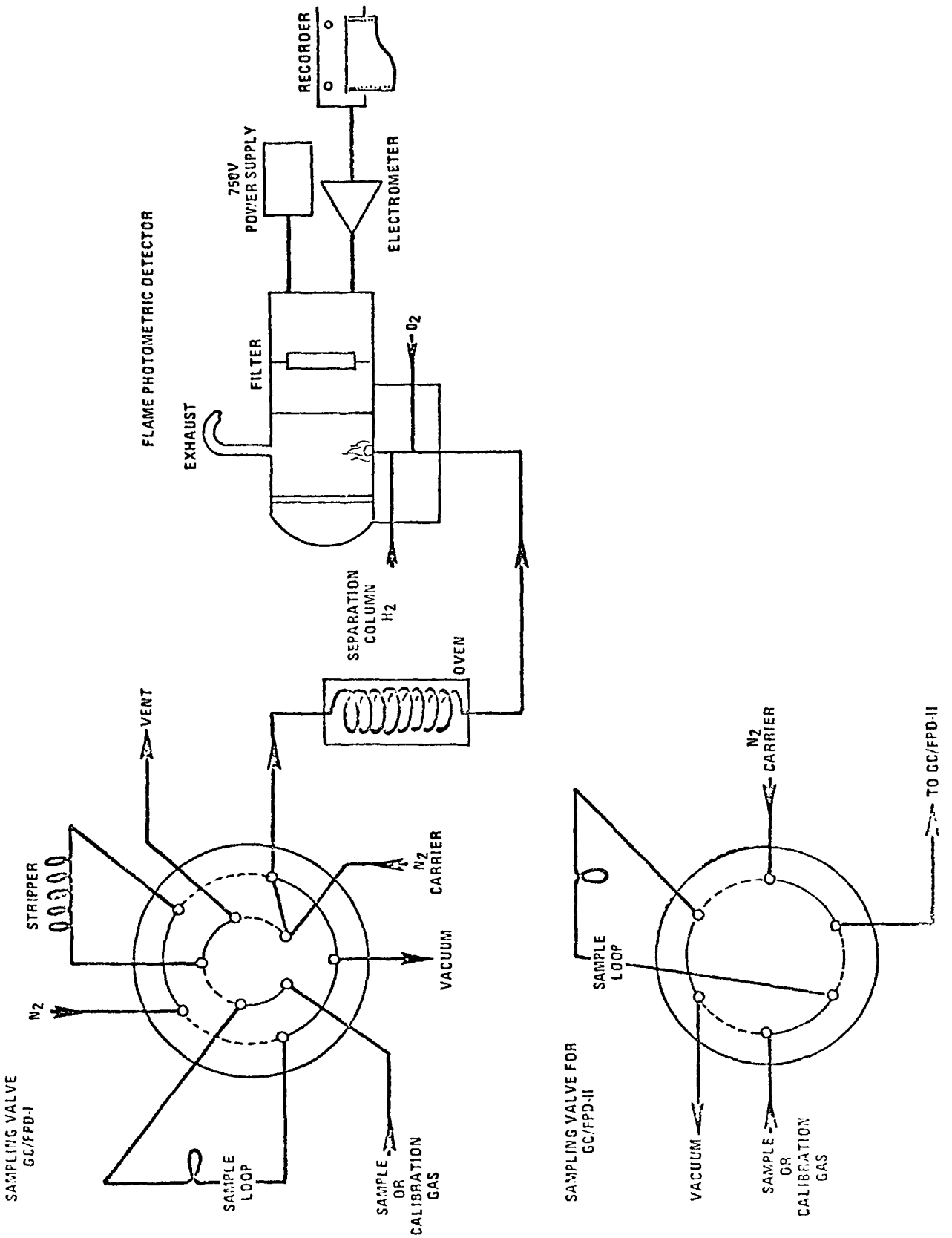


Figure 16-3. Gas chromatographic-flame photometric analyzers.

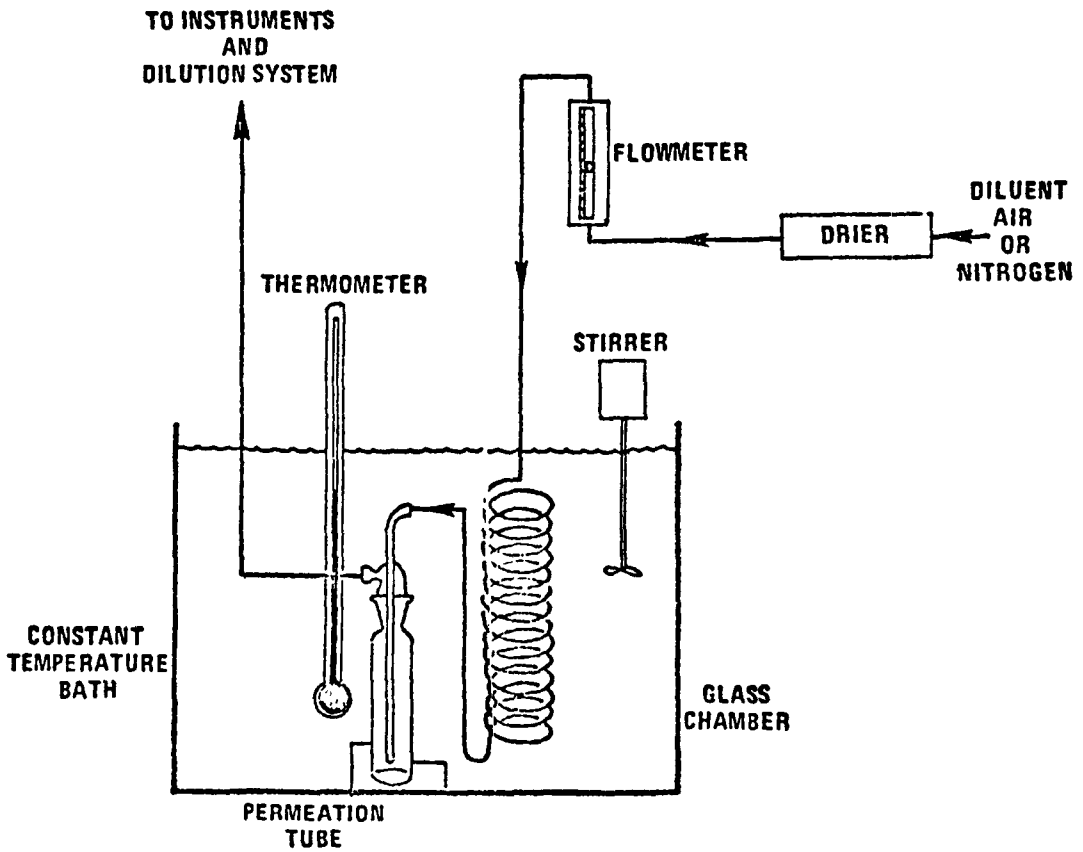


Figure 16-4. Apparatus for field calibration.

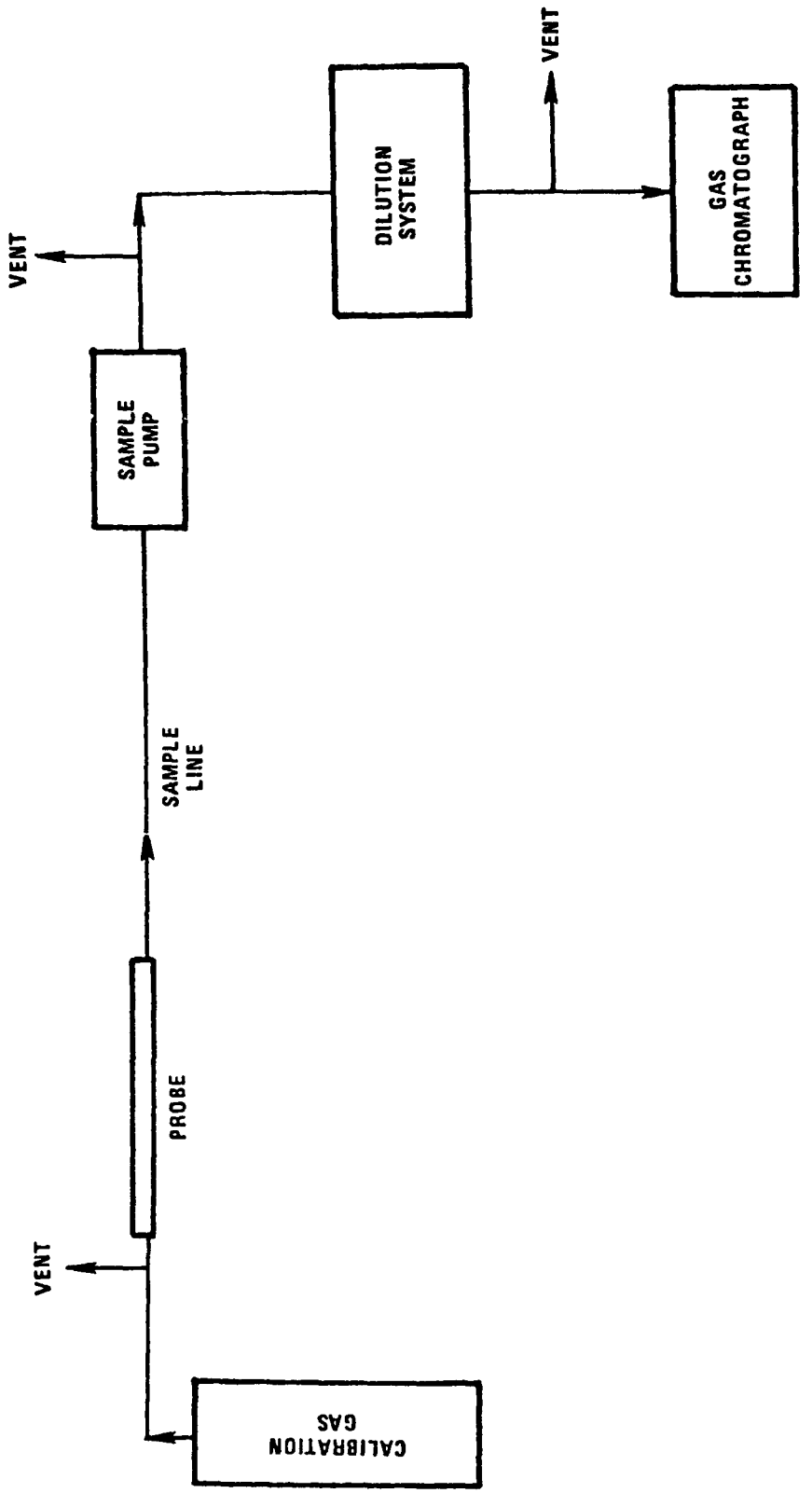


Figure 16- 5. Determination of sample line loss.

METHOD 17. DETERMINATION OF PARTICULATE EMISSIONS FROM STATIONARY SOURCES (IN-STACK FILTRATION METHOD)[82]

Introduction

Particulate matter is not an absolute quantity; rather, it is a function of temperature and pressure. Therefore, to prevent variability in particulate matter emission regulations and/or associated test methods, the temperature and pressure at which particulate matter is to be measured must be carefully defined. Of the two variables (i.e., temperature and pressure), temperature has the greater effect upon the amount of particulate matter in an effluent gas stream; in most stationary source categories, the effect of pressure appears to be negligible.

In method 5, 250° F is established as a nominal reference temperature. Thus, where Method 5 is specified in an applicable subpart of the standards, particulate matter is defined with respect to temperature. In order to maintain a collection temperature of 250° F, Method 5 employs a heated glass sample probe and a heated filter holder. This equipment is somewhat cumbersome and requires care in its operation. Therefore, where particulate matter concentrations (over the normal range of temperature associated with a specified source category) are known to be independent of temperature, it is desirable to eliminate the glass probe and heating systems, and sample at stack temperature.

This method describes an in-stack sampling system and sampling procedures for use in such cases. It is intended to be used only when specified by an applicable subpart of the standards, and only within the applicable temperature limits (if specified), or when otherwise approved by the Administrator.

1. *Principle and Applicability.*

1.1 Principle. Particulate matter is withdrawn isokinetically from the source and collected on a glass fiber filter maintained at stack temperature. The particulate mass is determined gravimetrically after removal of uncombined water.

1.2 Applicability. This method applies to the determination of particulate emissions from stationary sources for determining compliance with new source performance standards, only when specifically provided for in an applicable subpart of the standards. This method is not applicable to stacks that contain liquid droplets or are saturated with water vapor. In addition, this method shall not be used as written if the projected cross-sectional area of the probe extension-filter holder assembly covers more than 5 percent of the stack cross-sectional area (see Section 4.1.2).

2. *Apparatus.*

2.1 Sampling Train. A schematic of the sampling train used in this method is shown in Figure 17-1. Construction details for many, but not all, of the train components are given in APTD-0581 (Citation 2 in Section 7); for changes from the APTD-0581 document and for allowable modifications to Figure 17-1, consult with the Administrator.

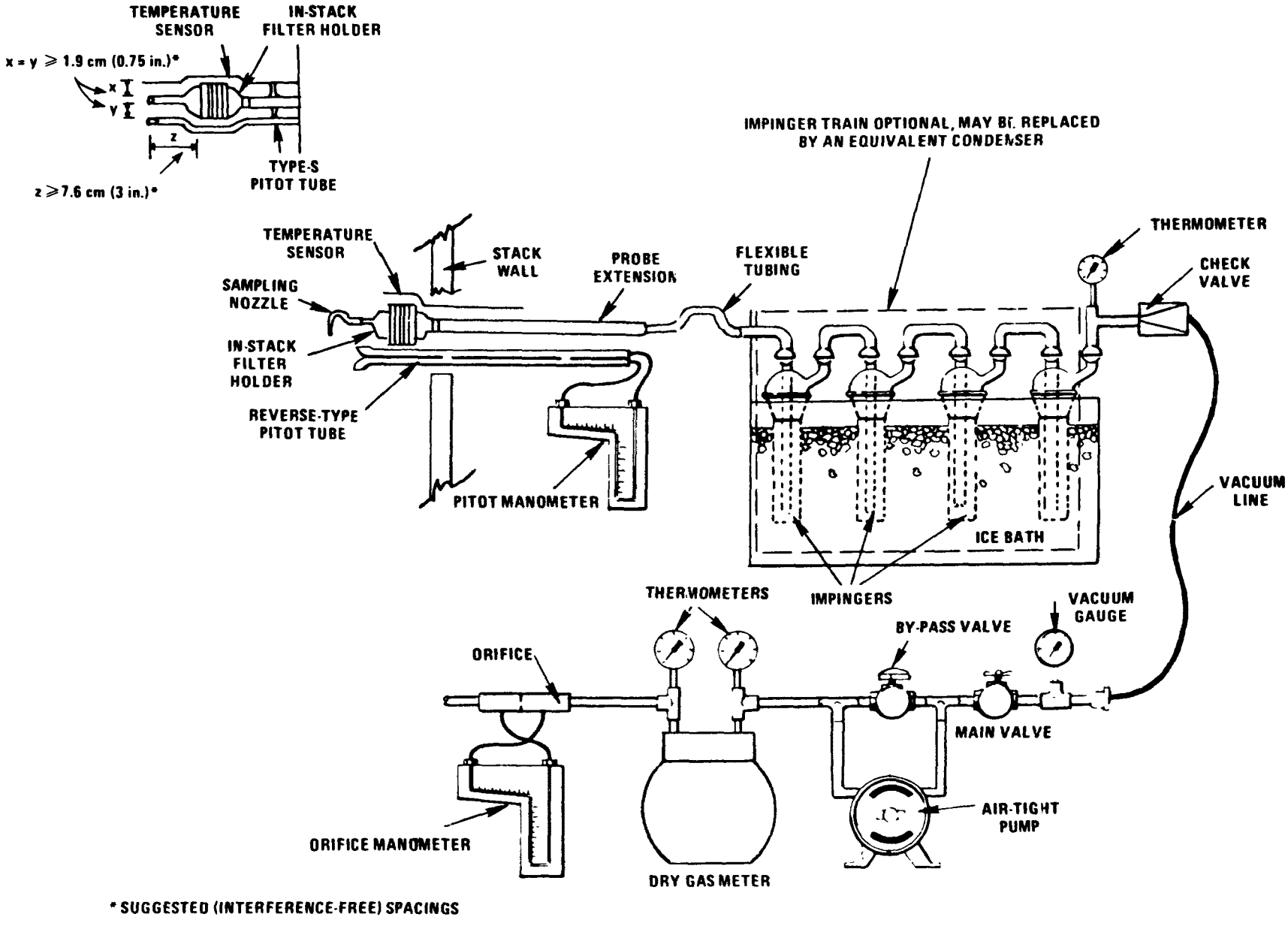


Figure 17-1. Particulate-Sampling Train, Equipped with In-Stack Filter.

The operating and maintenance procedures for many of the sampling train components are described in APTD-0576 (Citation 3 in Section 7). Since correct usage is important in obtaining valid results, all users should read the APTD-0576 document and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein. The sampling train consists of the following components:

2.1.1 Probe Nozzle. Stainless steel (316) or glass, with sharp, tapered leading edge. The angle of taper shall be 030° and the taper shall be on the outside to preserve a constant internal diameter. The probe nozzle shall be of the button-hook or elbow design, unless otherwise specified by the Administrator. If made of stainless steel, the nozzle shall be constructed from seamless tubing. Other materials of construction may be used subject to the approval of the Administrator.

A range of sizes suitable for isokinetic sampling should be available, e.g., 0.32 to 1.27 cm (⅛ to ½ in)—or larger if higher volume sampling trains are used—inside diameter (ID) nozzles in increments of 0.16 cm (1/16 in). Each nozzle shall be calibrated according to the procedures outlined in Section 5.1.

2.1.2 Filter Holder. The in-stack filter holder shall be constructed of borosilicate or quartz glass, or stainless steel; if a gasket is used, it shall be made of silicone rubber, Teflon, or stainless steel. Other holder and gasket materials may be used subject to the approval of the Administrator. The filter holder shall be designed to provide a positive seal against leakage from the outside or around the filter.

2.1.3 Probe Extension. Any suitable rigid probe extension may be used after the filter holder.

2.1.4 Pitot Tube. Type S, as described in Section 2.1 of Method 2, or other device approved by the Administrator; the pitot tube shall be attached to the probe extension to allow constant monitoring of the stack gas velocity (see Figure 17-1). The impact (high pressure) opening plane of the pitot tube shall be even with or above the nozzle entry plane during sampling (see Method 2, Figure 2-6b). It is recommended: (1) that the pitot tube have a known baseline coefficient, determined as outlined in Section 4 of Method 2; and (2) that this known coefficient be preserved by placing the pitot tube in an interference-free arrangement with respect to the sampling nozzle, filter holder, and temperature sensor (see Figure 17-1). Note that the 1.9 cm (0.75 in) free-space between the nozzle and pitot tube shown in Figure 17-1, is based on a 1.3 cm (0.5 in) ID nozzle. If the sampling train is designed for sampling at higher flow rates than that described in APTD-0581, thus necessitating the use of larger sized nozzles, the free-space shall be 1.9 cm (0.75 in) with the largest sized nozzle in place.

Source-sampling assemblies that do not meet the minimum spacing requirements of Figure 17-1 (or the equivalent of these requirements, e.g., Figure 2-7 of Method 2) may be used; however, the pitot tube coefficients of such assemblies shall be determined by calibration, using methods subject to the approval of the Administrator.

2.1.5 Differential Pressure Gauge. Inclined manometer or equivalent device (two), as described in Section 2.2 of Method 2. One manometer shall be used for velocity head (Δp) readings, and the other, for orifice differential pressure readings.

2.1.6 Condenser. It is recommended that the impinger system described in Method 5 be used to determine the moisture content of the stack gas. Alternatively, any system that allows measurement of both the water condensed and the moisture leaving the condenser, each to within 1 ml or 1 g, may be used. The moisture leaving the condenser can be measured either by: (1) monitoring the temperature and pressure at the exit of the condenser and using Dalton's law of partial pressures; or (2) passing the sample gas stream through a silica gel trap with exit gases kept below 20° C (68° F) and determining the weight gain.

Flexible tubing may be used between the probe extension and condenser. If means other than silica gel are used to determine the amount of moisture leaving the condenser, it is recommended that silica gel still be used between the condenser system and pump to prevent moisture condensation in the pump and metering devices and to avoid the need to make corrections for moisture in the metered volume.

2.1.7 Metering System. Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3° C (5.4° F), dry gas meter capable of measuring volume to within 2 percent, and related equipment, as shown in Figure 17-1. Other metering systems capable of maintaining sampling rates within 10 percent of isokinetic and of determining sample volumes to within 2 percent may be used, subject to the approval of the Administrator. When the metering system is used in conjunction with a pitot tube, the system shall enable checks of isokinetic rates.

Sampling trains utilizing metering systems designed for higher flow rates than that described in APTD-0581 or APTD-0576 may be used provided that the specifications of this method are met.

2.1.8 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.

2.1.9 Gas Density Determination Equipment. Temperature sensor and pressure gauge, as described in Sections 2.3 and 2.4 of Method 2, and gas analyzer, if necessary, as described in Method 3.

The temperature sensor shall be attached to either the pitot tube or to the probe extension, in a fixed configuration. If the temperature sensor is attached in the field; the sensor shall be placed in an interference-free arrangement with respect to the Type S pitot tube openings (as shown in Figure 17-1 or in Figure 2-7 of Method 2). Alternatively, the temperature sensor need not be attached to either the probe extension or pitot tube during sampling, provided that a difference of not more than 1 percent in the average velocity measurement is introduced. This alternative is subject to the approval of the Administrator.

2.2 Sample Recovery.

2.2.1 Probe Nozzle Brush. Nylon bristle brush with stainless steel wire handle. The brush shall be properly sized and shaped to brush out the probe nozzle.

2.2.2 Wash Bottles—Two. Glass wash bottles are recommended; polyethylene wash bottles may be used at the option of the tester. It is recommended that acetone not be stored in polyethylene bottles for longer than a month.

2.2.3 Glass Sample Storage Containers. Chemically resistant, borosilicate glass bottles, for acetone washes, 500 ml or 1000 ml. Screw cap liners shall either be rubber-backed Teflon or shall be constructed so as to be leak-free and resistant to chemical attack by acetone. (Narrow mouth glass bottles have been found to be less prone to leakage.) Alternatively, polyethylene bottles may be used.

2.2.4 Petri Dishes. For filter samples; glass or polyethylene, unless otherwise specified by the Administrator.

2.2.5 Graduated Cylinder and/or Balance. To measure condensed water to within 1 ml or 1 g. Graduated cylinders shall have subdivisions no greater than 2 ml. Most laboratory balances are capable of weighing to the nearest 0.5 g or less. Any of these balances is suitable for use here and in Section 2.3.4.

2.2.6 Plastic Storage Containers. Air tight containers to store silica gel.

2.2.7 Funnel and Rubber Policeman. To aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.

2.2.8 Funnel. Glass or polyethylene, to aid in sample recovery.

2.3 Analysis.

2.3.1 Glass Weighing Dishes.

2.3.2 Desiccator.

2.3.3 Analytical Balance. To measure to within 0.1 mg.

2.3.4 Balance. To measure to within 0.5 mg.

2.3.5 Beakers. 250 ml.

2.3.6 Hygrometer. To measure the relative humidity of the laboratory environment.

2.3.7 Temperature Gauge. To measure the temperature of the laboratory environment.

3. *Reagents.*

3.1 Sampling.

3.1.1 Filters. The in-stack filters shall be glass mats or thimble fiber filters, without organic binders, and shall exhibit at least 99.95 percent efficiency (00.05 percent penetration) on 0.3 micron dioctyl phthalate smoke particles. The filter efficiency tests shall be conducted in accordance with ASTM standard method D 2986-71. Test data from the supplier's quality control program are sufficient for this purpose.

3.1.2 Silica Gel. Indicating type, 6- to 16-mesh. If previously used, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to the approval of the Administrator.

3.1.3 Crushed Ice.

3.1.4 Stopcock Grease. Acetone-insoluble, heat-stable silicone grease. This is not necessary if screw-on connectors with Teflon sleeves, or similar, are used. Alternatively, other types of stopcock grease may be used, subject to the approval of the Administrator.

3.2 Sample Recovery. Acetone, reagent grade, 00.001 percent residue, in glass bottles. Acetone from metal containers generally has a high residue blank and should not be used. Sometimes, suppliers transfer acetone to glass bottles from metal containers. Thus, acetone blanks shall be run prior to field use and only acetone with low blank

values (00.001 percent) shall be used. In no case shall a blank value of greater than 0.001 percent of the weight of acetone used be subtracted from the sample weight.

3.3 Analysis.

3.3.1 Acetone. Same as 3.2.

3.3.2 Desiccant. Anhydrous calcium sulfate, indicating type. Alternatively, other types of desiccants may be used, subject to the approval of the Administrator.

4. *Procedure.*

4.1 Sampling. The complexity of this method is such that, in order to obtain reliable results, testers should be trained and experienced with the test procedures.

4.1.1 Pretest Preparation. All components shall be maintained and calibrated according to the procedure described in APTD-0576, unless otherwise specified herein.

Weigh several 200 to 300 g portions of silica gel in air-tight containers to the nearest 0.5 g. Record the total weight of the silica gel plus container, on each container. As an alternative, the silica gel need not be preweighed, but may be weighed directly in its impinger or sampling holder just prior to train assembly.

Check filters visually against light for irregularities and flaws or pinhole leaks. Label filters of the proper size on the back side near the edge using numbering machine ink. As an alternative, label the shipping containers (glass or plastic petri dishes) and keep the filters in these containers at all times except during sampling and weighing.

Desiccate the filters at 20±5.6° C (68±10° F) and ambient pressure for at least 24 hours and weigh at intervals of at least 6 hours to a constant weight, i.e., 00.5 mg change from previous weighing; record results to the nearest 0.1 mg. During each weighing the filter must not be exposed to the laboratory atmosphere for a period greater than 2 minutes and a relative humidity above 50 percent. Alternatively (unless otherwise specified by the Administrator), the filters may be oven dried at 105° C (220° F) for 2 to 3 hours, desiccated for 2 hours, and weighed. Procedures other than those described, which account for relative humidity effects, may be used, subject to the approval of the Administrator.

4.1.2 Preliminary Determinations. Select the sampling site and the minimum number of sampling points according to Method 1 or as specified by the Administrator. Make a projected-area model of the probe extension-filter holder assembly, with the pitot tube face openings positioned along the centerline of the stack, as shown in Figure 17-2. Calculate the estimated cross-section blockage, as shown in Figure 17-2. If the blockage exceeds 5 percent of the duct cross sectional area, the tester has the following options: (1) a suitable out-of-stack filtration method may be used instead of in-stack filtration; or (2) a special in-stack arrangement, in which the sampling and velocity measurement sites are separate, may be used; for details concerning this approach, consult with the Administrator (see also Citation 10 in Section 7). Determine the stack pressure, temperature, and the range of velocity heads using Method 2; it is recommended that a leak-check of the pitot lines (see Method 2, Section 3.1) be performed. Determine the moisture content using Approximation Method 4 or its alternatives for the purpose of making isokinetic sampling rate settings. Determine the stack gas dry molecular weight, as described in Method 2, Section 3.6; if integrated Method 3 sampling is used for molecular weight determination, the integrated bag sample shall be taken simultaneously with, and for the same total length of time as, the particular sample run.

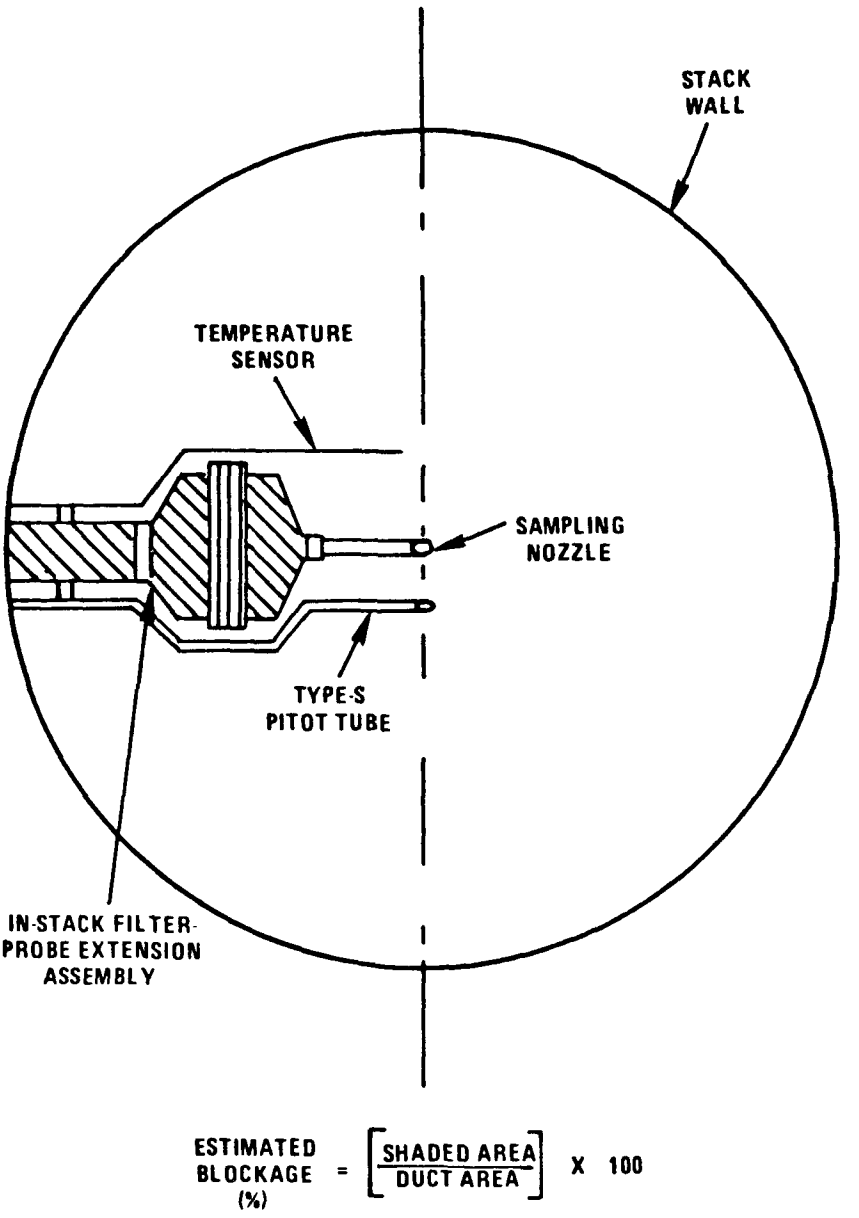


Figure 17-2. Projected-area model of cross-section blockage (approximate average for a sample traverse) caused by an in-stack filter holder-probe extension assembly.

Select a nozzle size based on the range of velocity heads, such that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates. During the run, do not change the nozzle size. Ensure that the proper differential pressure gauge is chosen for the range of velocity heads encountered (see Section 2.2 of Method 2).

Select a probe extension length such that all traverse points can be sampled. For large stacks, consider sampling from opposite sides of the stack to reduce the length of probes.

Select a total sampling time greater than or equal to the minimum total sampling time specified in the test procedures for the specific industry such that (1) the sampling time per point is not less than 2 minutes (or some greater time interval if specified by the Administrator), and (2) the sample volume taken (corrected to standard conditions) will exceed the required minimum total gas sample volume. The latter is based on an approximate average sampling rate.

It is recommended that the number of minutes sampled at each point be an integer or an integer plus one-half minute, in order to avoid timekeeping errors.

In some circumstances, e.g., batch cycles, it may be necessary to sample for shorter times at the traverse points and to obtain smaller gas sample volumes. In these cases, the Administrator's approval must first be obtained.

4.1.3 Preparation of Collection Train. During preparation and assembly of the sampling train, keep all openings where contamination can occur covered until just prior to assembly or until sampling is about to begin.

If impingers are used to condense stack gas moisture, prepare them as follows: place 100 ml of water in each of the first two impingers, leave the third impinger empty, and transfer approximately 200 to 300 g of preweighed silica gel from its container to the fourth impinger. More silica gel may be used, but care should be taken to ensure that it is not entrained and carried out from the impinger during sampling. Place the container in a clean place for later use in the sample recovery. Alternatively, the weight of the silica gel plus impinger may be determined to the nearest 0.5 g and recorded.

If some means other than impingers is used to condense moisture, prepare the condenser (and, if appropriate, silica gel for condenser outlet) for use.

Using a tweezer or clean disposable surgical gloves, place a labeled (identified) and weighed filter in the filter holder. Be sure that the filter is properly centered and the gasket properly placed so as not to allow the sample gas stream to circumvent the filter. Check filter for tears after assembly is completed. Mark the probe extension with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point.

Assemble the train as in Figure 17-1, using a very light coat of silicone grease on all ground glass joints and greasing only the outer portion (see APTD-0576) to avoid possibility of contamination by the silicone grease. Place crushed ice around the impingers.

4.1.4 Leak Check Procedures.

4.1.4.1 Pretest Leak-Check. A pretest leak-check is recommended, but not required. If the tester opts to conduct the pretest leak-check, the following procedure shall be used.

After the sampling train has been assembled, plug the inlet to the probe nozzle with a material that will be able to withstand the stack temperature. Insert the filter holder into the stack and wait approximately 5 minutes (or longer, if necessary) to allow the system to come to equilibrium with the temperature of the stack gas stream. Turn on the pump and draw a vacuum of at least 380 mm Hg (15 in. Hg); note that a lower vacuum may be used, provided that it is not exceeded during the test. Determine the leakage rate. A leakage rate in excess of 4 percent of the average sampling rate or 0.00057 m^3/min. (0.02 cfm), whichever is less, is unacceptable.

The following leak-check instructions for the sampling train described in APTD-0576 and APTD-0581 may be helpful. Start the pump with by-pass valve fully open and coarse adjust valve completely closed. Partially open the coarse adjust valve and slowly close the by-pass valve until the desired vacuum is reached. Do not reverse direction of by-pass valve. If the desired vacuum is exceeded, either leak-check at this higher vacuum or end the leak-check as shown below and start over.

When the leak-check is completed, first slowly remove the plug from the inlet to the probe nozzle and immediately turn off the vacuum pump. This prevents water from being forced backward and keeps silica gel from being entrained backward.

4.1.4.2 Leak-Checks During Sample Run. If, during the sampling run, a component (e.g., filter assembly or impinger) change becomes necessary, a leak-check shall be conducted immediately before the change is made. The leak-check shall be done according to the procedure outlined in Section 4.1.4.1 above, except that it shall be done at a vacuum equal to or greater than the maximum value recorded up to that point in the test. If the leakage rate is found to be no greater than 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction will need to be applied to the total volume of dry gas metered; if, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and plan to correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

Immediately after component changes, leak-checks are optional; if such leak-checks are done, the procedure outlined in Section 4.1.4.1 above shall be used.

4.1.4.3 Post-Test Leak-Check. A leak-check is mandatory at the conclusion of each sampling run. The leak-check shall be done in accordance with the procedures outlined in Section 4.1.4.1, except that it shall be conducted at a vacuum equal to or greater than the maximum value reached during the sampling run. If the leakage rate is found to be no greater than 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction need be applied to the total volume of dry gas metered. If, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

4.1.5 Particulate Train Operation. During the sampling run, maintain a sampling rate such that sampling is within 10 percent of true isokinetic, unless otherwise specified by the Administrator.

For each run, record the data required on the example data sheet shown in Figure 17-3. Be sure to record the initial dry gas meter reading. Record the dry gas meter readings at the beginning and end of each sampling time increment, when changes in flow rates are made, before and after each leak check, and when sampling is halted. Take other readings required by Figure 17-3 at least once at each sample point during each time increment and additional readings when significant changes (20 percent variation in velocity head readings) necessitate additional adjustments in flow rate. Level and zero the manometer. Because the manometer level and zero may drift due to vibrations and temperature changes, make periodic checks during the traverse.

PLANT _____

LOCATION _____

OPERATOR _____

DATE _____

RUN NO. _____

SAMPLE BOX NO. _____

METER BOX NO. _____

METER ΔH@ _____

C FACTOR _____

PITOT TUBE COEFFICIENT, C_p _____

SCHEMATIC OF STACK CROSS SECTION

BAROMETRIC PRESSURE _____

ASSUMED MOISTURE, % _____

PROBE EXTENSION LENGTH, m(ft.) _____

NOZZLE IDENTIFICATION NO. _____

AVERAGE CALIBRATED NOZZLE DIAMETER cm(in.) _____

FILTER NO. _____

LEAK RATE, m^3/min,(cfm) _____

STATIC PRESSURE, mm Hg (in. Hg) _____

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	VACUUM mm Hg (in. Hg)	STACK TEMPERATURE (T_S), °C (°F)	VELOCITY HEAD (ΔP_S), mm H_2O (in. H_2O)	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER, mm H_2O (in. H_2O)	GAS SAMPLE VOLUME, m^3 (ft^3)	GAS SAMPLE TEMPERATURE AT DRY GAS METER		TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °C (°F)
							INLET, °C (°F)	OUTLET, °C (°F)	
TOTAL							Avg	Avg	
AVERAGE							Avg		

Figure 17-3. Particulate field data.

Clean the portholes prior to the test run to minimize the chance of sampling the deposited material. To begin sampling, remove the nozzle cap and verify that the pitot tube and probe extension are properly positioned. Position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. Nomographs are available, which aid in the rapid adjustment to the isokinetic sampling rate without excessive computations. These nomographs are designed for use when the Type S pitot tube coefficient is 0.85±0.02, and the stack gas equivalent density (dry molecular weight) is equal to 29±4. APTD-0576 details the procedure for using the nomographs. If C_p and M_d are outside the above stated ranges, do not use the nomographs unless appropriate steps (see Citation 7 in Section 7) are taken to compensate for the deviations.

When the stack is under significant negative pressure (height of impinger stem), take care to close the coarse adjust valve before inserting the probe extension assembly into the stack to prevent water from being forced backward. If necessary, the pump may be turned on with the coarse adjust valve closed.

When the probe is in position, block off the openings around the probe and porthole to prevent unrepresentative dilution of the gas stream.

Traverse the stack cross section, as required by Method 1 or as specified by the Administrator, being careful not to bump the probe nozzle into the stack walls when sampling near the walls or when removing or inserting the probe extension through the portholes, to minimize chance of extracting deposited material.

During the test run, take appropriate steps (e.g., adding crushed ice to the impinger ice bath) to maintain a temperature of less than 20° C (68° F) at the condenser outlet; this will prevent excessive moisture losses. Also, periodically check the level and zero of the manometer.

If the pressure drop across the filter becomes too high, making isokinetic sampling difficult to maintain, the filter may be replaced in the midst of a sample run. It is recommended that another complete filter holder assembly be used rather than attempting to change the filter itself. Before a new filter holder is installed, conduct a leak check, as outlined in Section 4.1.4.2. The total particulate weight shall include the summation of all filter assembly catches.

A single train shall be used for the entire sample run, except in cases where simultaneous sampling is required in two or more separate ducts or at two or more different locations within the same duct, or, in cases where equipment failure necessitates a change of trains. In all other situations, the use of two or more trains will be subject to the approval of the Administrator. Note that when two or more trains are used, a separate analysis of the collected particulate from each train shall be performed, unless identical nozzle sizes were used on all trains, in which case the particulate catches from the individual trains may be combined and a single analysis performed.

At the end of the sample run, turn off the pump, remove the probe extension assembly from the stack, and record the final dry gas meter reading. Perform a leak-check, as outlined in Section 4.1.4.3. Also, leak-check the pitot lines as described in Section 3.1 of Method 2; the lines must pass this leak-check, in order to validate the velocity head data.

4.1.6 Calculation of Percent Isokinetic. Calculate percent isokinetic (see Section 6.11) to determine whether another test run should be made. If there is difficulty in maintaining isokinetic rates due to source conditions, consult with the Administrator for possible variance on the isokinetic rates.

4.2 Sample Recovery. Proper cleanup procedure begins as soon as the probe extension assembly is removed from the stack at the end of the sampling period. Allow the assembly to cool.

When the assembly can be safely handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it to prevent losing or gaining particulate matter. Do not cap off the probe tip tightly while the sampling train is cooling down as this would create a vacuum in the filter holder, forcing condenser water backward.

Before moving the sample train to the cleanup site, disconnect the filter holder-probe nozzle assembly from the probe extension; cap the open inlet of the probe extension. Be careful not to lose any condensate, if present. Remove the umbilical cord from the condenser outlet and cap the outlet. If a flexible line is used between the first impinger (or condenser) and the probe extension, disconnect the line at the probe extension and let any condensed water or liquid drain into the impingers or condenser. Disconnect the probe extension from the condenser; cap the probe extension outlet. After wiping off the silicone grease, cap off the condenser inlet. Ground glass stoppers, plastic caps, or serum caps (whichever are appropriate) may be used to close these openings.

Transfer both the filter holder-probe nozzle assembly and the condenser to the cleanup area. This area should be clean and protected from the wind so that the chances of contaminating or losing the sample will be minimized.

Save a portion of the acetone used for cleanup as a blank. Take 200 ml of this acetone directly from the wash bottle being used and place it in a glass sample container labeled "acetone blank."

Inspect the train prior to and during disassembly and note any abnormal conditions. Treat the samples as follows:

Container No. 1. Carefully remove the filter from the filter holder and place it in its identified petri dish container. Use a pair of tweezers and/or clean disposable surgical gloves to handle the filter. If it is necessary to fold the filter, do so such that the particulate cake is inside the fold. Carefully transfer to the petri dish any particulate matter and/or filter fibers which adhere to the filter holder gasket, by using a dry Nylon bristle brush and/or a sharp-edged blade. Seal the container.

Container No. 2. Taking care to see that dust on the outside of the probe nozzle or other exterior surfaces does not get into the sample, quantitatively recover particulate matter or any condensate from the probe nozzle, fitting, and front half of the filter holder by washing these components with acetone and placing the wash in a glass container. Distilled water may be used instead of acetone when approved by the Administrator and shall be used when specified by the Administrator; in these cases, save a water blank and follow Administrator's directions on analysis. Perform the acetone rinses as follows:

Carefully remove the probe nozzle and clean the inside surface by rinsing with acetone from a wash bottle and brushing with a Nylon bristle brush. Brush until acetone rinse shows no visible particles, after which make a final rinse of the inside surface with acetone.

Brush and rinse with acetone the inside parts of the fitting in a similar way until no visible particles remain. A funnel (glass or polyethylene) may be used to aid in transferring liquid washes to the container. Rinse the brush with acetone and quantitatively collect these washings in the sample container. Between sampling runs, keep brushes clean and protected from contamination.

After ensuring that all joints are wiped clean of silicone grease (if applicable), clean the inside of the front half of the filter holder by rubbing the surfaces with a Nylon bristle brush and rinsing with acetone. Rinse each surface three times or more if needed to remove visible particulate. Make final rinse of the brush and filter holder. After all acetone washings and particulate matter are collected in the sample container, tighten the lid on the sample container so that acetone will not leak out when it is shipped to the laboratory. Mark the height of the fluid level to determine whether or not leakage occurred during transport. Label the container to clearly identify its contents.

Container No. 3. If silica gel is used in the condenser system for mositure content determination, note the color of the gel to determine if it has been completely spent; make a notation of its condition. Transfer the silica gel back to its original container and seal. A funnel may make it easier to pour the silica gel without spilling, and a rubber policeman may be used as an aid in removing the silica gel. It is not necessary to remove the small amount of dust particles that may adhere to the walls and are difficult to remove. Since the gain in weight is to be used for moisture calculations, do not use any water or other liquids to transfer the silica gel. If a balance is available in the field, follow the procedure for Container No. 3 under "Analysis."

Condenser Water. Treat the condenser or impinger water as follows: make a notation of any color or film in the liquid catch. Measure the liquid volume to within ±1 ml by using a graduated cylinder or, if a balance is available, determine the liquid weight to within ±0.5 g. Record the total volume or weight of liquid present. This information is required to calculate the moisture content of the effluent gas. Discard the liquid after measuring and recording the volume or weight.

4.3 Analysis. Record the data required on the example sheet shown in Figure 17-4. Handle each sample container as follows:

Container No. 1. Leave the contents in the shipping container or transfer the filter and any loose particulate from the sample container to a tared glass weighing dish. Desiccate for 24 hours in a desiccator containing anhydrous calcium sulfate. Weigh to a constant weight and report the results to the nearest 0.1 mg. For purposes of this Section, 4.3, the term "constant weight" means a difference of no more than 0.5 mg or 1 percent of total weight less tare weight, whichever is greater, between two consecutive weighings, with no less than 6 hours of desiccation time between weighings.

Alternatively, the sample may be oven dried at the average stack temperature or

105° C (220° F), whichever is less, for 2 to 3 hours, cooled in the desiccator, and weighed to a constant weight, unless otherwise specified by the Administrator. The tester may also opt to oven dry the sample at the average stack temperature or 105° C (220° F), whichever is less, for 2 to 3 hours, weigh the sample, and use this weight as a final weight.

Plant _____

Date _____

Run No. _____

Filter No. _____

Amount liquid lost during transport _____

Acetone blank volume, ml _____

Acetone wash volume, ml _____

Acetone black concentration, mg/mg (equation 17-4) _____

Acetone wash blank, mg (equation 17-5) _____

CONTAINER NUMBER	WEIGHT OF PARTICULATE COLLECTED, mg		
	FINAL WEIGHT	TARE WEIGHT	WEIGHT GAIN
1			
2			
TOTAL			
		Less acetone blank	
		Weight of particulate matter	

	VOLUME OF LIQUID WATER COLLECTED		
	IMPINGER VOLUME, ml	SILICA GEL WEIGHT, g	
FINAL			
INITIAL			
LIQUID COLLECTED			
TOTAL VOLUME COLLECTED		g*	ml

* CONVERT WEIGHT OF WATER TO VOLUME BY DIVIDING TOTAL WEIGHT INCREASE BY DENSITY OF WATER (1g/ml).

$$\frac{\text{INCREASE, g}}{\text{1 g/ml}} = \text{VOLUME WATER, ml}$$

Figure 17-4. Analytical data.

Container No. 2. Note the level of liquid in the container and confirm on the analysis sheet whether or not leakage occurred during transport. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results. Measure the liquid in this container either volumetrically to ±1 ml or gravimetrically to ±0.5 g. Transfer the contents to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

Container No. 3. This step may be conducted in the field. Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g using a balance.

"Acetone Blank" Container. Measure acetone in this container either volumetrically or gravimetrically. Transfer the acetone to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

NOTE.—At the option of the tester, the contents of Container No. 2 as well as the acetone blank container may be evaporated at temperatures higher than ambient. If evaporation is done at an elevated temperature, the temperature must be below the boiling point of the solvent; also, to prevent "bumping," the evaporation process must be closely supervised, and the contents of the beaker must be swirled occasionally to maintain an even temperature. Use extreme care, as acetone is highly flammable and has a low flash point.

5. *Calibration.* Maintain a laboratory log of all calibrations.

5.1 Probe Nozzle. Probe nozzles shall be calibrated before their initial use in the field. Using a micrometer, measure the inside diameter of the nozzle to the nearest 0.025 mm (0.001 in.). Make three separate measurements using different diameters each time, and obtain the average of the measurements. The difference between the high and low numbers shall not exceed 0.1 mm (0.004 in.). When nozzles become nicked, dented, or corroded, they shall be reshaped, sharpened, and recalibrated before use. Each nozzle shall be permanently and uniquely identified.

5.2 Pitot Tube. If the pitot tube is placed in an interference-free arrangement with respect to the other probe assembly components, its baseline (isolated tube) coefficient shall be determined as outlined in Section 4 of Method 2. If the probe assembly is not interference-free, the pitot tube assembly coefficient shall be determined by calibration, using methods subject to the approval of the Administrator.

5.3 Metering System. Before its initial use in the field, the metering system shall be calibrated according to the procedure outlined in APTD-0576. Instead of physically adjusting the dry gas meter dial readings to correspond to the wet test meter readings, calibration factors may be used to mathematically correct the gas meter dial readings to the proper values.

Before calibrating the metering system, it is suggested that a leak-check be conducted. For metering systems having diaphragm pumps, the normal leak-check procedure will not detect leakages within the pump. For these cases the following leak-check procedure is suggested: make a 10-minute calibration run at 0.00057 m^3/min (0.02 cfm); at the end of the run, take the difference of the measured wet test meter and dry gas meter volumes; divide the difference by 10, to get the leak rate. The leak rate should not exceed 0.00057 m^3/min (0.02 cfm).

After each field use, the calibration of the metering system shall be checked by performing three calibration runs at a single, intermediate orifice setting (based on the previous field test), with the vacuum set at the maximum value reached during the test series. To adjust the vacuum, insert a valve between the wet test meter and the inlet of the metering system. Calculate the average value of the calibration factor. If the calibration has changed by more than 5 percent, recalibrate the meter over the full range of orifice settings, as outlined in APTD-0576.

Alternative procedures, e.g., using the orifice meter coefficients, may be used, subject to the approval of the Administrator.

NOTE.—If the dry gas meter coefficient values obtained before and after a test series differ by more than 5 percent, the test series shall either be voided, or calculations for the test series shall be performed using whichever meter coefficient value (i.e., before or after) gives the lower value of total sample volume.

5.4 Temperature Gauges. Use the procedure in Section 4.3 of Method 2 to calibrate in-stack temperature gauges. Dial thermometers, such as are used for the dry gas meter and condenser outlet, shall be calibrated against mercury-in-glass thermometers.

5.5 Leak Check of Metering System Shown in Figure 17-1. That portion of the sampling train from the pump to the orifice meter should be leak checked prior to initial use and after each shipment. Leakage after the pump will result in less volume being recorded than is actually sampled. The following procedure is suggested (see Figure 17-5). Close the main valve on the meter box. Insert a one-hole rubber stopper with rubber tubing attached into the orifice exhaust pipe. Disconnect and vent the low side of the orifice manometer. Close off the low side orifice tap. Pressurize the system to 13 to 18 cm (5 to 7 in.) water column by blowing into the rubber tubing. Pinch off the tubing and observe the manometer for one minute. A loss of pressure on the manometer indicates a leak in the meter box; leaks, if present, must be corrected.

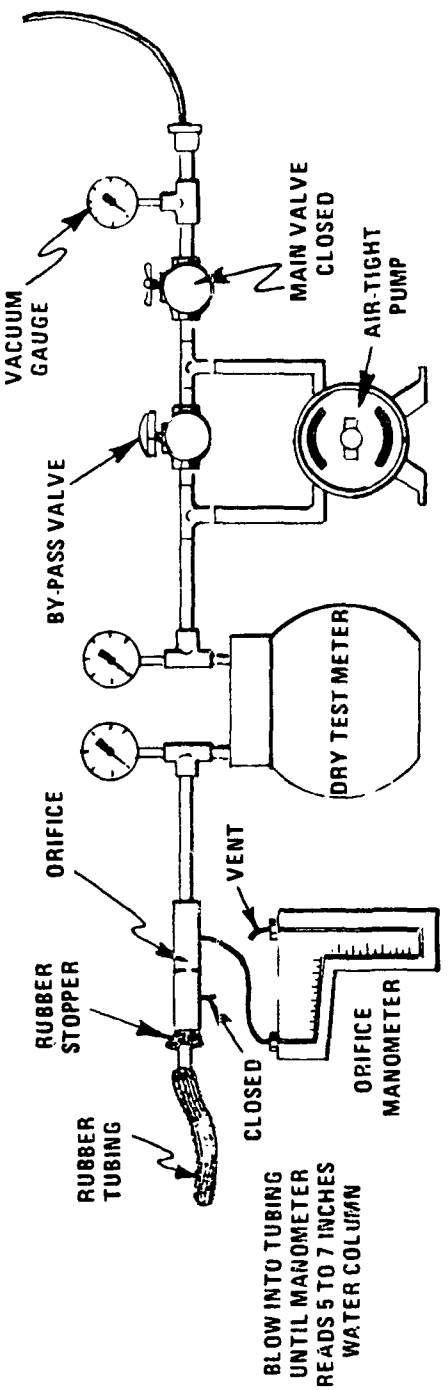


Figure 17-5. Leak check of meter box.

5.6 Barometer. Calibrate against a mercury barometer.

6. *Calculations.* Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after the final calculation. Other forms of the equations may be used as long as they give equivalent results.

6.1 Nomenclature.

A_n = Cross-sectional area of nozzle, m^2 (ft^2).
B_{ws} = Water vapor in the gas stream, proportion by volume.
C_a = Acetone blank residue concentration, mg/g.
c_s = Concentration of particulate matter in stack gas, dry basis, corrected to standard conditions, g/dscm (g/dscf).
I = Percent of isokinetic sampling.
L_a = Maximum acceptable leakage rate for either a pretest leak check or for a leak check following a component change; equal to 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate, whichever is less.
L_i = Individual leakage rate observed during the leak check conducted prior to the "i^{th}" component change (i = 1, 2, 3 . . . n), m^3/min (cfm).
L_p = Leakage rate observed during the post-test leak check, m^3/min (cfm).
m_n = Total amount of particulate matter collected, mg.
M_w = Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).
m_a = Mass of residue of acetone after evaporation, mg.
P_{bar} = Barometric pressure at the sampling site, mm Hg (in. Hg).
P_s = Absolute stack gas pressure, mm Hg (in. Hg).
P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).
R = Ideal gas constant, 0.06236 mm Hg-m^3/°K-g-mole (21.85 in. Hg-ft^3/°R-lb-mole).
T_m = Absolute average dry gas meter temperature (see Figure 17-3), °K (°R).
T_s = Absolute average stack gas temperature (see Figure 17-3), °K (°R).
T_{std} = Standard absolute temperature, 293°K (528°R).
V_a = Volume of acetone blank, ml.
V_{aw} = Volume of acetone used in wash, ml.
V_{lc} = Total volume of liquid collected in impingers and silica gel (see Figure 17-4), ml.
V_m = Volume of gas sample as measured by dry gas meter, dcm (dcf).
$V_{m(std)}$ = Volume of gas sample measured by the dry gas meter, corrected to standard conditions, dscm (dscf).
$V_{w(std)}$ = Volume of water vapor in the gas sample, corrected to standard conditions, scm (scf).
v_s = Stack gas velocity, calculated by Method 2, Equation 2-9, using data obtained from Method 17, m/sec (ft/sec).
W_a = Weight of residue in acetone wash, mg.
Y = Dry gas meter calibration coefficient.
ΔH = Average pressure differential across the orifice meter (see Figure 17-3), mm H_2O (in. H_2O).
ρ_a = Density of acetone, mg/ml (see label on bottle).
ρ_w = Density of water, 0.9982 g/ml (0.002201 lb/ml).
θ = Total sampling time, min.
θ_1 = Sampling time interval, from the beginning of a run until the first component change, min.
θ_i = Sampling time interval, between two successive component changes, beginning with the interval between the first and second changes, min.

θ_p = Sampling time interval, from the final (n^{th}) component change until the end of the sampling run, min.
13.6 = Specific gravity of mercury.
60 = Sec/min.
100 = Conversion to percent.

6.2 *Average dry gas meter temperature and average orifice pressure drop.* See data sheet (Figure 17-3).

6.3 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20° C, 760 mm Hg or 68° F, 29.92 in. Hg) by using Equation 17-1.

$$V_{m(std)} = V_m Y \left(\frac{T_{std}}{T_m}\right)\left[\frac{P_{bar} + \frac{\Delta H}{13.6}}{P_{std}}\right]$$

$$= K_1 V_m Y \frac{P_{bar} + (\Delta H/13.6)}{T_m}$$

Equation 17-1

where:

K_1 = 0.3858° K/mm Hg for metric units; 17.64° R/in. Hg for English units.

NOTE.—Equation 17-1 can be used as written unless the leakage rate observed during any of the mandatory leak checks (i.e., the post-test leak check or leak checks conducted prior to component changes) exceeds L_a. If L_p or L_i exceeds L_a, Equation 17-1 must be modified as follows:

(a) Case I. No component changes made during sampling run. In this case, replace V_m in Equation 17-1 with the expression:

$$[V_m - (L_p - L_a)\theta]$$

(b) Case II. One or more component changes made during the sampling run. In this case, replace V_m in Equation 17-1 by the expression:

$$\{V_m - (L_1 - L_a)\,\theta_1 - \sum_{i=2}^{n} (L_i - L_a)\,\theta_i - (L_p - L_a)\,\theta_p\}$$

and substitute only for those leakage rates (L_i or L_p) which exceed L_a.

6.4 Volume of water vapor.

$$V_{w(std)} = V_{lc}\left(\frac{\rho_w}{M_w}\right)\left(\frac{RT_{std}}{P_{std}}\right) = K_2 V_{lc}$$

Equation 17-2

where:

K_2 = 0.001333 m³/ml for metric units; 0.04707 ft³/ml for English units.

6.5 Moisture Content.

$$B_{ws} = \frac{V_{w(std)}}{V_{m(std)} + V_{w(std)}}$$

Equation 17-3

6.6 Acetone Blank Concentration.

$$C_a = \frac{m_a}{V_a \rho_a}$$

Equation 17-4

6.7 Acetone Wash Blank.

$$W_a = C_a V_{aw} \rho_a$$

Equation 17-5

6.8 Total Particulate Weight. Determine the total particulate catch from the sum of the weights obtained from containers 1 and 2 less the acetone blank (see Figure 17-4).

NOTE.—Refer to Section 4.1.5 to assist in calculation of results involving two or more filter assemblies or two or more sampling trains.

6.9 Particulate Concentration.

$$c_s = (0.001\ g/mg)\,(m_n/V_{m(std)})$$

Equation 17-6

6.10 Conversion Factors:

From	To	Multiply by
scf	m³	0.02832
g/ft³	gr/ft³	15.43
g/ft³	lb/ft³	2.205×10^{-3}
g/ft³	g/m³	35.31

6.11 Isokinetic Variation.

6.11.1 Calculation from Raw Data.

$$I = \frac{100\,T_s\,[K_3 V_{lc} + (V_m Y/T_m)\,(P_{bar} + \Delta H/13.6)]}{60\,\theta v_s P_s A_n}$$

Equation 17-7

where:

K_3 = 0.003454 mm Hg-m³/ml-°K for metric units; 0.002669 in. Hg-ft³/ml-°R for English units.

6.11.2 Calculation from Intermediate Values.

$$I = \frac{T_s\,V_{m(std)}\,P_{std}\,100}{T_{std}\,v_s\,\theta\,A_n\,P_s\,60\,(1-B_{ws})}$$

$$= K_4 \frac{T_s\,V_{m(std)}}{P_s\,v_s\,A_n\,\theta\,(1-B_{ws})}$$

Equation 17-8

where:

K_4 = 4.320 for metric units; 0.09450 for English units

6.12 Acceptable Results. If 90 percent ≤ I ≤ 110 percent, the results are acceptable. If the results are low in comparison to the standard and I is beyond the acceptable range, or, if I is less than 90 percent, the Administrator may opt to accept the results. Use Citation 4 in Section 7 to make judgments. Otherwise, reject the results and repeat the test.

7. *Bibliography.*

1. Addendum to Specifications for Incinerator Testing at Federal Facilities. PHS, NCAPC. December 6, 1967.

2. Martin, Robert M., Construction Details of Isokinetic Source-Sampling Equipment. Environmental Protection Agency. Research Triangle Park, N.C. APTD-0581. April, 1971.

3. Rom, Jerome J., Maintenance, Calibration, and Operation of Isokinetic Source-Sampling Equipment. Environmental Protection Agency. Research Triangle Park, N.C. APTD-0576. March, 1972.

4. Smith, W. S., R. T. Shigehara, and W. F. Todd. A Method of Interpreting Stack Sampling Data. Paper Presented at the 63rd Annual Meeting of the Air Pollution Control Association, St. Louis, Mo. June 14-19, 1970.

5. Smith, W. S., et al., Stack Gas Sampling Improved and Simplified with New Equipment. APCA Paper No. 67-119. 1967.

6. Specifications for Incinerator Testing at Federal Facilities. PHS, NCAPC. 1967.

7. Shigehara, R. T., Adjustments in the EPA Nomograph for Different Pitot Tube Coefficients and Dry Molecular Weights. Stack Sampling News 2:4-11. October, 1974.

8. Vollaro, R. F., A Survey of Commercially Available Instrumentation for the Measurement of Low-Range Gas Velocities. U.S. Environmental Protection Agency, Emission Measurement Branch. Research Triangle Park, N.C. November, 1976 (unpublished paper).

9. Annual Book of ASTM Standards. Part 26. Gaseous Fuels; Coal and Coke; Atmospheric Analysis. American Society for Testing and Materials. Philadelphia, Pa. 1974. pp. 617-622.

10. Vollaro, R. F., Recommended Procedure for Sample Traverses in Ducts Smaller than 12 Inches in Diameter. U.S. Environmental Protection Agency, Emission Measurement Branch. Research Triangle Park, N.C. November, 1976.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). 68,83

Method 19. Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide and Nitrogen Oxides Emission Rates From Electric Utility Steam Generators [98]

1. *Principle and Applicability*

1.1 *Principle.*

1.1.1 Fuel samples from before and after fuel pretreatment systems are collected and analyzed for sulfur and heat content, and the percent sulfur dioxide (ng/Joule, lb/million Btu) reduction is calculated on a dry basis. (Optional Procedure.)

1.1.2 Sulfur dioxide and oxygen or carbon dioxide concentration data obtained from sampling emissions upstream and downstream of sulfur dioxide control devices are used to calculate sulfur dioxide removal efficiencies. (Minimum Requirement.) As an alternative to sulfur dioxide monitoring upstream of sulfur dioxide control devices, fuel samples may be collected in an as-fired condition and analyzed for sulfur and heat content. (Optional Procedure.)

1.1.3 An overall sulfur dioxide emission reduction efficiency is calculated from the efficiency of fuel pretreatment systems and the efficiency of sulfur dioxide control devices.

1.1.4 Particulate, sulfur dioxide, nitrogen oxides, and oxygen or carbon dioxide concentration data obtained from sampling emissions downstream from sulfur dioxide control devices are used along with F factors to calculate particulate, sulfur dioxide, and nitrogen oxides emission rates. F factors are values relating combustion gas volume to the heat content of fuels.

1.2 *Applicability.* This method is applicable for determining sulfur removal efficiencies of fuel pretreatment and sulfur dioxide control devices and the overall reduction of potential sulfur dioxide emissions from electric utility steam generators. This method is also applicable for the determination of particulate, sulfur dioxide, and nitrogen oxides emission rates.

2. *Determination of Sulfur Dioxide Removal Efficiency of Fuel Pretreatment Systems*

2.1 *Solid Fossil Fuel.*

2.1.1 *Sample Increment Collection.* Use ASTM D 2234 [1], Type I, conditions A, B, or C, and systematic spacing. Determine the number and weight of increments required per gross sample representing each coal lot according to Table 2 or Paragraph 7.1.5.2 of ASTM D 2234 [1]. Collect one gross sample for each raw coal lot and one gross sample for each product coal lot.

2.1.2 *ASTM Lot Size.* For the purpose of Section 2.1.1, the product coal lot size is defined as the weight of product coal produced from one type of raw coal. The raw coal lot size is the weight of raw coal used to produce one product coal lot. Typically, the lot size is the weight of coal processed in a 1-day (24 hours) period. If more than one type of coal is treated and produced in 1 day, then gross samples must be collected and analyzed for each type of coal. A coal lot size equaling the 90-day quarterly fuel quantity for a specific power plant may be used if representative sampling can be conducted for the raw coal and product coal.

Note.—Alternate definitions of fuel lot sizes may be specified subject to prior approval of the Administrator.

2.1.3 *Gross Sample Analysis.* Determine the percent sulfur content (%S) and gross calorific value (GCV) of the solid fuel on a dry basis for each gross sample. Use ASTM 2013 [1] for sample preparation, ASTM D 3177 [1] for sulfur analysis, and ASTM D 3173 [1] for moisture analysis. Use ASTM D 3176 [1] for gross calorific value determination.

2.2 *Liquid Fossil Fuel.*

2.2.1 *Sample Collection.* Use ASTM D 270 [1] following the practices outlined for continuous sampling for each gross sample representing each fuel lot.

2.2.2 *Lot Size.* For the purposes of Section 2.2.1, the weight of product fuel from one pretreatment facility and intended as one shipment (ship load, barge load, etc.) is defined as one product fuel lot. The weight of each crude liquid fuel type used to produce one product fuel lot is defined as one inlet fuel lot.

Note.— Alternate definitions of fuel lot sizes may be specified subject to prior approval of the Administrator.

Note.— For the purposes of this method, raw or inlet fuel (coal or oil) is defined as the fuel delivered to the desulfurization pretreatment facility or to the steam generating plant. For pretreated oil the input oil to the oil desulfurization process (e.g. hydrotreatment emitted) is sampled.

2.2.3 *Sample Analysis.* Determine the percent sulfur content (%S) and gross calorific value (GCV). Use ASTMD 240 [1] for the sample analysis. This value can be assumed to be on a dry basis.

2.3 *Calculation of Sulfur Dioxide Removal Efficiency Due to Fuel Pretreatment.* Calculate the percent sulfur dioxide reduction due to fuel pretreatment using the following equation:

$$\%R_f = 100\left[1 - \frac{\%S_o/GCV_o}{\%S_i/GCV_i}\right]$$

Where:

$\%R_f$ = Sulfur dioxide removal efficiency due pretreatment; percent.

$\%S_o$ = Sulfur content of the product fuel lot on a dry basis; weight percent.

$\%S_i$ = Sulfur content of the inlet fuel lot on a dry basis; weight percent.

GCV_o = Gross calorific value for the outlet fuel lot on a dry basis; kJ/kg (Btu/lb).

GCV_i = Gross calorific value for the inlet fuel lot on a dry basis; kJ/kg (Btu/lb).

Note.—If more than one fuel type is used to produce the product fuel, use the following equation to calculate the sulfur contents per unit of heat content of the total fuel lot, %S/GCV:

$$\%S/GCV = \sum_{k=1}^{n} Y_k(\%S_k/GCV_k)$$

Where:

Y_k = The fraction of total mass input derived from each type, k, of fuel.

$\%S_k$ = Sulfur content of each fuel type, k, on a dry basis; weight percent.

GCV_k = Gross calorific value for each fuel type, k, on a dry basis; kJ/kg (Btu/lb).

n = The number of different types of fuels.

[1] Use the most recent revision or designation of the ASTM procedure specified.

[1] Use the most recent revision or designation of the ASTM procedure specified.

3. *Determination of Sulfur Removal Efficiency of the Sulfur Dioxide Control Device*

3.1 *Sampling.* Determine SO_2 emission rates at the inlet and outlet of the sulfur dioxide control system according to methods specified in the applicable subpart of the regulations and the procedures specified in Section 5. The inlet sulfur dioxide emission rate may be determined through fuel analysis (Optional, see Section 3.3.)

3.2. *Calculation.* Calculate the percent removal efficiency using the following equation:

$$\%R_{g(m)} = 100 \times \left(1.0 - \frac{E_{SO_2 o}}{E_{SO_2 i}}\right)$$

Where:

$\%R_g$ = Sulfur dioxide removal efficiency of the sulfur dioxide control system using inlet and outlet monitoring data; percent.

$E_{SO_2 o}$ = Sulfur dioxide emission rate from the outlet of the sulfur dioxide control system; ng/J (lb/million Btu).

$E_{SO_2 i}$ = Sulfur dioxide emission rate to the outlet of the sulfur dioxide control system; ng/J (lb/million Btu).

3.3 *As-fired Fuel Analysis (Optional Procedure).* If the owner or operator of an electric utility steam generator chooses to determine the sulfur dioxide imput rate at the inlet to the sulfur dioxide control device through an as-fired fuel analysis in lieu of data from a sulfur dioxide control system inlet gas monitor, fuel samples must be collected in accordance with applicable paragraph in Section 2. The sampling can be conducted upstream of any fuel processing, e.g., plant coal pulverization. For the purposes of this section, a fuel lot size is defined as the weight of fuel consumed in 1 day (24 hours) and is directly related to the exhaust gas monitoring data at the outlet of the sulfur dioxide control system.

3.3.1 *Fuel Analysis.* Fuel samples must be analyzed for sulfur content and gross calorific value. The ASTM procedures for determining sulfur content are defined in the applicable paragraphs of Section 2.

3.3.2 *Calculation of Sulfur Dioxide Input Rate.* The sulfur dioxide imput rate determined from fuel analysis is calculated by:

$$I_s = \frac{2.0(\%S_f)}{GCV} \times 10^7 \quad \text{for S. I. units.}$$

$$I_s = \frac{2.0(\%S_f)}{GCV} \times 10^4 \quad \text{for English units.}$$

Where:

I_s = Sulfur dioxide input rate from as-fired fuel analysis, ng/J (lb/million Btu).

$\%S_f$ = Sulfur content of as-fired fuel, on a dry basis; weight percent.

GCV = Gross calorific value for as-fired fuel, on a dry basis; kJ/kg (Btu/lb).

3.3.3 *Calculation of Sulfur Dioxide Emission Reduction Using As-fired Fuel Analysis.* The sulfur dioxide emission reduction efficiency is calculated using the sulfur imput rate from paragraph 3.3.2 and the sulfur dioxide emission rate, E_{SO_2}, determined in the applicable paragraph of Section 5.3. The equation for sulfur dioxide emission reduction efficiency is:

$$\%R_{g(f)} = 100 \times \left(1.0 - \frac{E_{SO_2}}{I_s}\right)$$

Where:

$\%R_{g(f)}$ = Sulfur dioxide removal efficiency of the sulfur dioxide control system using as-fired fuel analysis data; percent.

E_{SO_2} = Sulfur dioxide emission rate from sulfur dioxide control system; ng/J (lb/million Btu).

I_s = Sulfur dioxide input rate from as-fired fuel analysis; ng/J (lb/million Btu).

4. *Calculation of Overall Reduction in Potential Sulfur Dioxide Emission*

4.1 The overall percent sulfur dioxide reduction calculation uses the sulfur dioxide concentration at the inlet to the sulfur dioxide control device as the base value. Any sulfur reduction realized through fuel cleaning is introduced into the equation as an average percent reduction, $\%R_f$.

4.2 Calculate the overall percent sulfur reduction as:

$$\%R_o = 100\left[1.0 - \left(1.0 - \frac{\%R_f}{100}\right)\left(1.0 - \frac{\%R_g}{100}\right)\right]$$

Where:

$\%R_o$ = Overall sulfur dioxide reduction; percent.

$\%R_f$ = Sulfur dioxide removal efficiency of fuel pretreatment from Section 2; percent. Refer to applicable subpart for definition of applicable averaging period.

$\%R_g$ = Sulfur dioxide removal efficiency of sulfur dioxide control device either O_2 or CO_2 - based calculation or calculated from fuel analysis and emission data, from Section 3; percent. Refer to applicable subpart for definition of applicable averaging period.

5. *Calculation of Particulate, Sulfur Dioxide, and Nitrogen Oxides Emission Rates*

5.1 *Sampling.* Use the outlet SO_2 or O_2 or CO_2 concentrations data obtained in Section 3.1. Determine the particulate, NO_x, and O_2 or CO_2 concentrations according to methods specified in an applicable subpart of the regulations.

5.2 *Determination of an F Factor.* Select an average F factor (Section 5.2.1) or calculate an applicable F factor (Section 5.2.2.). If combined fuels are fired, the selected or calculated F factors are prorated using the procedures in Section 5.2.3. F factors are ratios of the gas volume released during combustion of a fuel divided by the heat content of the fuel. A dry F factor (F_d) is the ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted; a wet F factor (F_w) is the ratio of the volume of wet flue gases generated to the calorific value of the fuel combusted; and the carbon F factor (F_c) is the ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted. When pollutant and oxygen concentrations have been determined in Section 5.1, wet or dry F factors are used. (F_w) factors and associated emission calculation procedures are not applicable and may not be used after wet scrubbers; (F_c) or (F_d) factors and associated emission calculation procedures are used after wet scrubbers.) When pollutant and carbon dioxide concentrations have been determined in Section 5.1, F_c factors are used.

5.2.1 *Average F Factors.* Table 1 shows average F_d, F_w, and F_c factors (scm/J, scf/million Btu) determined for commonly used fuels. For fuels not listed in Table 1, the F factors are calculated according to the procedures outlined in Section 5.2.2 of this section.

5.2.2 *Calculating an F Factor.* If the fuel burned is not listed in Table 1 or if the owner or operator chooses to determine an F factor rather than use the tabulated data, F factors are calculated using the equations below. The sampling and analysis procedures followed in obtaining data for these calculations are subject to the approval of the Administrator and the Administrator should be consulted prior to data collection.

For SI Units:

$$F_d = \frac{227.0(\%H) + 95.7(\%C) + 35.4(\%S) + 8.6(\%N) - 28.5(\%O)}{GCV}$$

$$F_w = \frac{347.4(\%H)+95.7(\%C)+35.4(\%S)+8.6(\%N)-28.5(\%O)+13.0(\%H_2O)^{**}}{GCV_w}$$

$$F_c = \frac{20.0(\%C)}{GCV}$$

For English Units:

$$F_d = \frac{10^6[5.57(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)]}{GCV}$$

$$F_w = \frac{10^6[5.57(\%H)+1.53(\%C)+0.57(\%S)+0.14(\%N)-0.46(\%O)+0.21(\%H_2O)^{**}]}{GCV_w}$$

$$F_c = \frac{10^6[0.321(\%C)]}{GCV}$$

** The $\%H_2O$ term may be omitted if %H and %O include the unavailable hydrogen and oxygen in the form of H_2O.

Where:

F_d, F_w, and F_c have the units of scm/J, or scf/million Btu; %H, %C, %S, %N, %O, and $\%H_2O$ are the concentrations by weight (expressed in percent) of hydrogen, carbon, sulfur, nitrogen, oxygen, and water from an ultimate analysis of the fuel; and GCV is the gross calorific value of the fuel in kJ/kg or Btu/lb and consistent with the ultimate analysis. Follow ASTM D 2015* for solid fuels, D 240* for liquid fuels, and D 1826* for gaseous fuels as applicable in determining GCV.

5.2.3 *Combined Fuel Firing F Factor.* For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F_d, F_w, or F_c factors determined by Sections 5.2.1 or 5.2.2 of this section shall be prorated in accordance with applicable formula as follows:

$$F_d = \sum_{k=1}^{n} x_k F_{dk} \quad \text{or}$$

$$F_w = \sum_{k=1}^{n} x_k F_{wk} \quad \text{or}$$

$$F_c = \sum_{k=1}^{n} x_k F_{ck}$$

Where:

x_k = The fraction of total heat input derived from each type of fuel, K.

n = The number of fuels being burned in combination.

5.3 *Calculation of Emission Rate.* Select from the following paragraphs the applicable calculation procedure and calculate the particulate, SO_2, and NO_x emission rate. The values in the equations are defined as:

E = Pollutant emission rate, ng/J (lb/million Btu).

C = Pollutant concentration, ng/scm (lb/scf).

Note.—It is necessary in some cases to convert measured concentration units to other units for these calculations.

Use the following table for such conversions:

Conversion Factors for Concentration

From—	To—	Multiply by—
g/scm	ng/scm	10^9
mg/scm	ng/scm	10^6
lb/scf	ng/scm	1.602×10^{12}
ppm(SO_2)	ng/scm	2.660×10^6
ppm(NO_2)	ng/scm	1.912×10^6
ppm/(SO_2)	lb/scf	1.660×10^{-7}
ppm/(NO_2)	lb/scf	1.194×10^{-7}

5.3.1 *Oxygen-Based F Factor Procedure.*

5.3.1.1 *Dry Basis.* When both percent oxygen ($\%O_{2d}$) and the pollutant concentration (C_d) are measured in the flue gas on a dry basis, the following equation is applicable:

$$E = C_d F_d \left[\frac{20.9}{20.9 - \%O_{2d}}\right]$$

5.3.1.2 *Wet Basis.* When both the percent oxygen ($\%O_{2w}$) and the pollutant concentration (C_w) are measured in the flue gas on a wet basis, the following equations are applicable: (Note: F_w factors are not applicable after wet scrubbers.)

(a) $$E = C_w F_w \left[\frac{20.9}{20.9(1 - B_{wa}) - \%O_{2w}}\right]$$

Where:

B_{wa} = Proportion by volume of water vapor in the ambient air.

In lieu of actual measurement, B_{wa} may be estimated as follows:

Note.—The following estimating factors are selected to assure that any negative error introduced in the term:

$$\left(\frac{20.9}{20.9(1 - B_{wa}) - \%O_{2ws}}\right)$$

will not be larger than −1.5 percent. However, positive errors, or overestimation of emissions, of as much as 5 percent may be introduced depending upon the geographic location of the facility and the associated range of ambient mositure.

(i) $B_{wa} = 0.027$. This factor may be used as a constant value at any location.

(ii) B_{wa} = Highest monthly average of B_{wa} which occurred within a calendar year at the nearest Weather Service Station.

(iii) B_{wa} = Highest daily average of B_{wa} which occurred within a calendar month at the nearest Weather Service Station, calculated from the data for the past 3 years. This factor shall be calculated for each month and may be used as an estimating factor for the respective calendar month.

(b) $$E = C_w F_d \left[\frac{20.9}{20.9\,(1 - B_{ws}) - \%O_{2w}}\right]$$

Where:

B_{ws} = Proportion by volume of water vapor in the stack gas.

5.3.1.3 *Dry/Wet Basis.* When the pollutant concentration (C_w) is measured on a wet basis and the oxygen concentration ($\%O_{2d}$) or measured on a dry basis, the following equation is applicable:

$$E = \left[\frac{C_w F_d}{(1 - B_{ws})}\right] \left[\frac{20.9}{20.9 - \%O_{2d}}\right]$$

When the pollutant concentration (C_d) is measured on a dry basis and the oxygen concentration ($\%O_{2d}$) is measured on a wet basis, the following equation is applicable:

$$E = C_d F_d \frac{20.9}{20.9 - \frac{\%O_{2w}}{(1 - B_{ws})}}$$

5.3.2 *Carbon Dioxide-Based F Factor Procedure.*

5.3.2.1 *Dry Basis.* When both the percent carbon dioxide ($\%CO_{2d}$) and the pollutant concentration (C_d) are measured in the flue gas on a dry basis, the following equation is applicable:

$$E = C_d F_c \left(\frac{100}{\%CO_{2d}}\right)$$

5.3.2.2 *Wet Basis.* When both the percent carbon dioxide ($\%CO_{2w}$) and the pollutant concentration (C_w) are measured on a wet basis, the following equation is applicable:

$$E = C_w F_c \left(\frac{100}{\%CO_{2w}}\right)$$

5.3.2.3 *Dry/Wet Basis.* When the pollutant concentration (C_w) is measured on a wet basis and the percent carbon dioxide ($\%CO_{2d}$) is measured on a dry basis, the following equation is applicable:

$$E = \left[\frac{C_w F_c}{(1 - B_{ws})}\right] \left[\frac{100}{\%CO_{2d}}\right]$$

When the pollutant concentration (C_d) is measured on a dry basis and the precent carbon dioxide ($\%CO_{2w}$) is measured on a wet basis, the following equation is applicable:

$$E = C_d (1 - B_{ws}) F_c \left(\frac{100}{\%CO_{2w}}\right)$$

5.4 *Calculation of Emission Rate from Combined Cycle-Gas Turbine Systems.* For gas turbine-steam generator combined cycle systems, the emissions from supplemental fuel fired to the steam generator or the percentage reduction in potential (SO_2) emissions cannot be determined directly. Using measurements from the gas turbine exhaust (performance test, subpart GG) and the combined exhaust gases from the steam generator, calculate the emission rates for these two points following the appropriate paragraphs in Section 5.3.

Note.—F_w factors shall not be used to determine emission rates from gas turbines because of the injection of steam nor to calculate emission rates after wet scrubbers; F_d or F_c factor and associated calculation procedures are used to combine effluent emissions according to the procedure in Paragraph 5.2.3.

The emission rate from the steam generator is calculated as:

$$E_{sg} = \frac{E_c - X_{gt} E_{gt}}{X_{sg}}$$

Where:

E_{sg} = Pollutant emission rate from steam generator effluent, ng/J (lb/million Btu).
E_c = Pollutant emission rate in combined cycle effluent; ng/J (lb/million Btu).
E_{gt} = Pollutant emission rate from gas turbine effluent; ng/J (lb/million Btu).
X_{sg} = Fraction of total heat input from supplemental fuel fired to the steam generator.
X_{gt} = Fraction of total heat input from gas turbine exhaust gases.

Note.—The total heat input to the steam generator is the sum of the heat input from supplemental fuel fired to the steam generator and the heat input to the steam generator from the exhaust gases from the gas turbine.

5.5 *Effect of Wet Scrubber Exhaust, Direct-Fired Reheat Fuel Burning.* Some wet scrubber systems require that the temperature of the exhaust gas be raised above the moisture dew-point prior to the gas entering the stack. One method used to accomplish this is directfiring of an auxiliary burner into the exhaust gas. The heat required for such burners is from 1 to 2 percent of total heat input of the steam generating plant. The effect of this fuel burning on the exhaust gas components will be less than ±1.0 percent and will have a similar effect on emission rate calculations. Because of this small effect, a determination of effluent gas constituents from direct-fired reheat burners for correction of stack gas concentrations is not necessary.

Table 19-1.—*F Factors for Various fuels*[c]

Fuel type	F_d		F_w		F_c	
	dscm/J	dscf/10^6 Btu	wscm/J	wscf/10^6 Btu	scm/J	scf/10^6 Btu
Coal:						
Anthracite[a]	2.71×10^{-7}	(10100)	2.83×10^{-7}	(10540)	0.530×10^{-7}	(1970)
Bituminous[a]	2.63×10^{-7}	(9780)	2.86×10^{-7}	(10640)	0.484×10^{-7}	(1800)
Lignite	2.65×10^{-7}	(9860)	3.21×10^{-7}	(11950)	0.513×10^{-7}	(1910)
Oil[b]	2.47×10^{-7}	(9190)	2.77×10^{-7}	(10320)	0.383×10^{-7}	(1420)
Gas:						
Natural	2.43×10^{-7}	(8710)	2.85×10^{-7}	(10610)	0.287×10^{-7}	(1040)
Propane	2.34×10^{-7}	(8710)	2.74×10^{-7}	(10200)	0.321×10^{-7}	(1190)
Butane	2.34×10^{-7}	(8710)	2.79×10^{-7}	(10390)	0.337×10^{-7}	(1250)
Wood	2.48×10^{-7}	(9240)			0.492×10^{-7}	(1830)
Wood Bark	2.58×10^{-7}	(9600)			0.497×10^{-7}	(1850)

[a] As classified according to ASTM D 388-66.
[b] Crude, residual, or distillate
[c] Determined at standard conditions 20° C (68° F) and 760 mm Hg (29.92 in. Hg).

6. *Calculation of Confidence Limits for Inlet and Outlet Monitoring Data*

6.1 *Mean Emission Rates.* Calculate the mean emission rates using hourly averages in ng/J (lb/million Btu) for SO_2 and NO_x outlet data and, if applicable, SO_2 inlet data using the following equations:

$$E_o = \frac{\Sigma x_o}{n_o},$$

$$E_i = \frac{\Sigma x_i}{n_i}$$

Where:

E_o = Mean outlet emission rate; ng/J (lb/million Btu).
E_i = Mean inlet emission rate; ng/J (lb/million Btu).
x_o = Hourly average outlet emission rate; ng/J (lb/million Btu).
x_i = Hourly average in let emission rate; ng/j (lb/million Btu).
n_o = Number of outlet hourly averages available for the reporting period.
n_i = Number of inlet hourly averages available for reporting period.

6.2 *Standard Deviation of Hourly Emission Rates.* Calculate the standard deviation of the available outlet hourly average emission rates for SO_2 and NO_x and, if applicable, the available inlet hourly average emission rates for SO_2 using the following equations:

$$s_o = \left(\sqrt{\frac{1}{n_o} - \frac{1}{720}}\right)\left(\sqrt{\frac{\Sigma (E_o - x_o)^2}{n_o - 1}}\right)$$

$$s_i = \left(\sqrt{\frac{1}{n_i} - \frac{1}{720}}\right)\left(\sqrt{\frac{\Sigma (E_i - x_i)^2}{n_i - 1}}\right)$$

Where:

s_o = Standard deviation of the average outlet hourly average emission rates for the reporting period; ng/J (lb/million Btu).
s_i = Standard deviation of the average inlet hourly average emission rates for the reporting period; ng/J (lb/million Btu).

6.3 *Confidence Limits.* Calculate the lower confidence limit for the mean outlet emission rates for SO_2 and NO_x and, if applicable, the upper confidence limit for the mean inlet emission rate for SO_2 using the following equations:

$E_o^* = E_o - t_{.o.95} s_o$
$E_i^* = E_i + t_{.o.95} s_i$

Where:

E_o^* = The lower confidence limit for the mean outlet emission rates; ng/J (lb/million Btu).
E_i^* = The upper confidence limit for the mean inlet emission rate; ng/J (lb/million Btu).
$t_{.o.95}$ = Values shown below for the indicated number of available data points (n):

n	Values for $t_{.o.95}$	$t_{.95}$
2		6.31
3		2.42
4		2.35
5		2.13
6		2.02
7		1.94
8		1.89
9		1.86
10		1.83
11		1.81
12-16		1.77
17-21		1.73
22-26		1.71
27-31		1.70
32-51		1.68
52-91		1.67
92-151		1.66
152 or more		1.65

The values of this table are corrected for n-1 degrees of freedom. Use n equal to the number of hourly average data points.

7. *Calculation to Demonstrate Compliance When Available Monitoring Data Are Less Than the Required Minimum*

7.1 *Determine Potential Combustion Concentration (PCC) for SO_2.*

7.1.1 When the removal efficiency due to fuel pretreatment (% R_f) is included in the overall reduction in potential sulfur dioxide emissions (% R_o) and the "as-fired" fuel analysis is **not** used, the potential combustion concentration (PCC) is determined as follows:

$$PCC = E_i^* + 2\left(\frac{\%\ S_i}{GCV_i} - \frac{\%\ S_o}{GCV_o}\right) 10^7;\ ng/J$$

$$PCC = E_i^* + 2\left(\frac{\%\ S_i}{GCV_i} - \frac{\%\ S_o}{GCV_o}\right) 10^4;\ lb/million\ Btu.$$

Where:

$\left(\frac{\%\ S_i}{GCV_i} - \frac{\%\ S_o}{GCV_o}\right)$ = Potential emissions removed by the pretreatment process, using the fuel parameters defined in section 2.3; ng/J (lb/million Btu).

7.1.2 When the "as-fired" fuel analysis is used and the removal efficiency due to fuel pretreatment (% R_f) is not included in the overall reduction in potential sulfur dioxide emissions (% R_o), the potential combustion concentration (PCC) is determined as follows:

$PCC = I_s$

Where:

I_s = The sulfur dioxide input rate as defined in section 3.3

7.1.3 When the "as-fired" fuel analysis is used and the removal efficiency due to fuel pretreatment (% R_f) is included in the overall reduction (% R_o), the potential combustion concentration (PCC) is determined as follows:

$$PCC = I_s + 2\left(\frac{\%\ S_f}{GCV_f} - \frac{\%\ S_o}{GCV_o}\right)10^7;\ ng/J$$

$$PCC = I_s + 2\left(\frac{\%\ S_f}{GCV_f} - \frac{\%\ S_o}{GCV_o}\right)10^4;\ lb/million\ Btu.$$

7.1.4 When inlet monitoring data are used and the removal efficiency due to fuel pretreatment (% R_f) is not included in the overall reduction in potential sulfur dioxide emissions (% R_o), the potential combustion concentration (PCC) is determined as follows:

$PCC = E_i^*$

Where:

E_i^* = The upper confidence limit of the mean inlet emission rate, as determined in section 6.3.

7.2 *Determine Allowable Emission Rates (E_{std}).*

7.2.1 *NO_x.* Use the allowable emission rates for NO_x as directly defined by the applicable standard in terms of ng/J (lb/million Btu).

7.2.2 *SO_2.* Use the potential combustion concentration (PCC) for SO_2 as determined in section 7.1, to determine the applicable emission standard. If the applicable standard is an allowable emission rate in ng/J (lb/million Btu), the allowable emission rate is used as E_{std}. If the applicable standard is an allowable percent emission, calculate the allowable emission rate (E_{std}) using the following equation:

$E_{std} = \%\ PCC/100$

Where:

% PCC = Allowable percent emission as defined by the applicable standard; percent.

7.3 *Calculate E_o^*/E_{std}.* To determine compliance for the reporting period calculate the ratio:

E_o^*/E_{std}

Where:

E_o^* = The lower confidence limit for the mean outlet emission rates, as defined in section 6.3; ng/J (lb/million Btu).

E_{std} = Allowable emission rate as defined in section 7.2; ng/J (lb/million Btu).

If E_o^*/E_{std} is equal to or less than 1.0, the facility is in compliance; if E_o^*/E_{std} is greater than 1.0, the facility is not in compliance for the reporting period.

Method 20—Determination of Nitrogen Oxides, Sulfur Dioxide, and Oxygen Emissions from Stationary Gas Turbines

1. Applicability and Principle

1.1 Applicability. This method is applicable for the determination of nitrogen oxides (NO_x), sulfur dioxide (SO_2), and oxygen (O_2) emissions from stationary gas turbines. For the NO_x and O_2 determinations, this method includes: (1) measurement system design criteria, (2) analyzer performance specifications and performance test procedures; and (3) procedures for emission testing.

1.2 Principle. A gas sample is continuously extracted from the exhaust stream of a stationary gas turbine; a portion of the sample stream is conveyed to instrumental analyzers for determination of NO_x and O_2 content. During each NO_x and OO_2 determination, a separate measurement of SO_2 emissions is made, using Method 6, or it equivalent. The O_2 determination is used to adjust the NO_x and SO_2 concentrations to a reference condition.

2. Definitions

2.1 Measurement System. The total equipment required for the determination of a gas concentration or a gas emission rate. The system consists of the following major subsystems:

2.1.1 Sample Interface. That portion of a system that is used for one or more of the following: sample acquisition, sample transportation, sample conditioning, or protection of the analyzers from the effects of the stack effluent.

2.1.2 NO_x Analyzer. That portion of the system that senses NO_x and generates an output proportional to the gas concentration.

2.1.3 O_2 Analyzer. That portion of the system that senses O_2 and generates an output proportional to the gas concentration.

2.2 Span Value. The upper limit of a gas concentration measurement range that is specified for affected source categories in the applicable part of the regulations.

2.3 Calibration Gas. A known concentration of a gas in an appropriate diluent gas.

2.4 Calibration Error. The difference between the gas concentration indicated by the measurement system and the known concentration of the calibration gas.

2.5 Zero Drift. The difference in the measurement system output readings before and after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place and the input concentration at the time of the measurements was zero.

2.6 Calibration Drift. The difference in the measurement system output readings before and after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place and the input at the time of the measurements was a high-level value.

2.7 Residence Time. The elapsed time from the moment the gas sample enters the probe tip to the moment the same gas sample reaches the analyzer inlet.

2.8 Response Time. The amount of time required for the continuous monitoring system to display on the data output 95 percent of a step change in pollutant concentration.

2.9 Interference Response. The output response of the measurement system to a component in the sample gas, other than the gas component being measured.

3. Measurement System Performance Specifications

3.1 NO_2 to NO Converter. Greater than 90 percent conversion efficiency of NO_2 to NO.

3.2 Interference Response. Less than ± 2 percent of the span value.

3.3 Residence Time. No greater than 30 seconds.

3.4 Response Time. No greater than 3 minutes.

3.5 Zero Drift. Less than ± 2 percent of the span value.

3.6 Calibration Drift. Less than ± 2 percent of the span value.

4. Apparatus and Reagents

4.1 Measurement System. Use any measurement system for NO_x and O_2 that is expected to meet the specifications in this method. A schematic of an acceptable measurement system is shown in Figure 20–1. The essential components of the measurement system are described below:

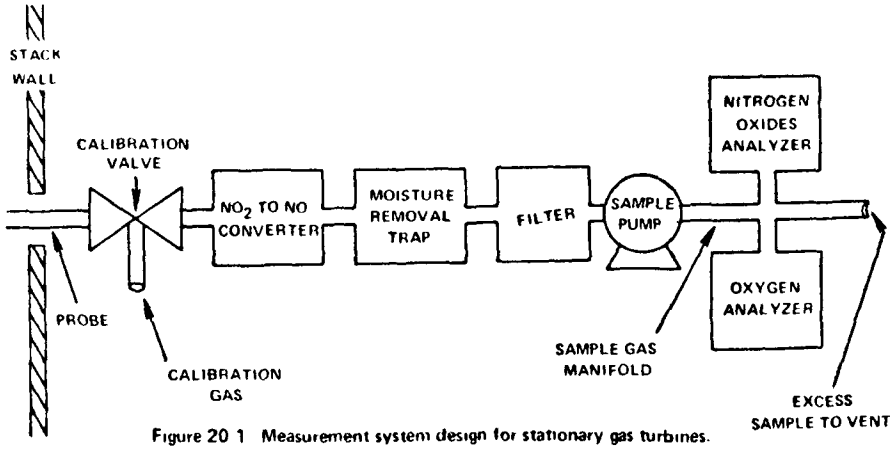


Figure 20 1 Measurement system design for stationary gas turbines.

4.1.1 Sample Probe. Heated stainless steel, or equivalent, open-ended, straight tube of sufficient length to traverse the sample points.

4.1.2 Sample Line. Heated (>95°C) stainless steel or Teflon tubing to transport the sample gas to the sample conditioners and analyzers.

4.1.3 Calibration Valve Assembly. A three-way valve assembly to direct the zero and calibration gases to the sample conditioners and to the analyzers. The calibration valve assembly shall be capable of blocking the sample gas flow and of introducing calibration gases to the measurement system when in the calibration mode.

4.1.4 NO_2 to NO Converter. That portion of the system that converts the nitrogen dioxide (NO_2) in the sample gas to nitrogen oxide (NO). Some analyzers are designed to measure NO_x as NO_2 on a wet basis and can be used without an NO_2 to NO converter or a moisture removal trap provided the sample line to the analyzer is heated (>95°C) to the inlet of the analyzer. In addition, an NO_2 to NO converter is not necessary if the NO_2 portion of the exhaust gas is less than 5 percent of the total NO_x concentration. As a guideline, an NO_2 to NO converter is not necessary if the gas turbine is operated at 90 percent or more of peak load capacity. A converter is necessary under lower load conditions.

4.1.5 Moisture Removal Trap. A refrigerator-type condenser designed to continuously remove condensate from the sample gas. The moisture removal trap is not necessary for analyzers that can measure NO_x concentrations on a wet basis; for these analyzers, (a) heat the sample line up to the inlet of the analyzers, (b) determine the moisture content using methods subject to the approval of the Administrator, and (c) correct the NO_x and O_2 concentrations to a dry basis.

4.1.6 Particulate Filter. An in-stack or an out-of-stack glass fiber filter, of the type specified in EPA Reference Method 5; however, an out-of-stack filter is recommended when the stack gas temperature exceeds 250 to 300°C.

4.1.7 Sample Pump. A nonreactive leak-free sample pump to pull the sample gas through the system at a flow rate sufficient to minimize transport delay. The pump shall be made from stainless steel or coated with Teflon or equivalent.

4.1.8 Sample Gas Manifold. A sample gas manifold to divert portions of the sample gas stream to the analyzers. The manifold may be constructed of glass, Teflon, type 316 stainless steel, or equivalent.

4.1.9 Oxygen and Analyzer. An analyzer to determine the percent O_2 concentration of the sample gas stream.

4.1.10 Nitrogen Oxides Analyzer. An analyzer to determine the ppm NO_x concentration in the sample gas stream.

4.1.11 Data Output. A strip-chart recorder, analog computer, or digital recorder for recording measurement data.

4.2 Sulfur Dioxide Analysis. EPA Reference Method 6 apparatus and reagents.

4.3 NO_x Caliberation Gases. The calibration gases for the NO_x analyzer may be NO in N_2, NO_2 in air or N_2, or NO and NO_2

in N_2. For NO_x measurement analyzers that require oxidation of NO to NO_2, the calibration gases must be in the form of NO in N_2. Use four calibration gas mixtures as specified below:

4.3.1 High-level Gas. A gas concentration that is equivalent to 80 to 90 percent of the span value.

4.3.2 Mid-level Gas. A gas concentration that is equivalent to 45 to 55 percent of the span value.

4.3.3 Low-level Gas. A gas concentration that is equivalent to 20 to 30 percent of the span value.

4.3.4 Zero Gas. A gas concentration of less than 0.25 percent of the span value. Ambient air may be used for the NO_x zero gas.

4.4 O_2 Calibration Gases. Use ambient air at 20.9 percent as the high-level O_2 gas. Use a gas concentration that is equivalent to 11–14 percent O_2 for the mid-level gas. Use purified nitrogen for the zero gas.

4.5 NO_2/NO Gas Mixture. For determining the conversion efficiency of the NO_2 to NO converter, use a calibration gas mixture of NO_2 and NO in N_2. The mixture will be known concentrations of 40 to 60 ppm NO_2 and 90 to 110 ppm NO and certified by the gas manufacturer. This certification of gas concentration must include a brief description of the procedure followed in determining the concentrations.

5 Measurement System Performance Test Procedures

Perform the following procedures prior to measurement of emissions (Section 6) and only once for each test program, i.e., the series of all test runs for a given gas turbine engine.

5.1 Calibration Gas Checks. There are two alternatives for checking the concentrations of the calibration gases. (a) The first is to use calibration gases that are documented traceable to National Bureau of Standards Reference Materials. Use *Traceability Protocol for Establishing True Concentrations of Gases Used for Calibrations and Audits of Continuous Source Emission Monitors* (Protocol Number 1) that is available from the Environmental Monitoring and Support Laboratory, Quality Assurance Branch, Mail Drop 77, Environmental Protection Agency, Research Triangle Park, North Carolina 27711. Obtain a certification from the gas manufacturer that the protocol was followed. These calibration gases are not to be analyzed with the Reference Methods. (b) The second alternative is to use calibration gases not prepared according to the protocol. If this alternative is chosen, within 1 month prior to the emission test, analyze each of the calibration gas mixtures in triplicate using Reference Method 7 or the procedure outlined in Citation 8.1 for NO_x and use Reference Method 3 for O_2. Record the results on a data sheet (example is shown in Figure 20–2). For the low-level, mid-level, or high-level gas mixtures, each of the individual NO_x analytical results must be within 10 percent (or 10 ppm, whichever is greater) of the triplicate set average (O_2 test results must be within 0.5 percent O_2); otherwise, discard the entire set and repeat the triplicate analyses. If the average of the triplicate reference method test results is within 5 percent for NO_x gas or 0.5 percent O_2 for the O_2 gas of the calibration gas manufacturer's tag value, use the tag value; otherwise, conduct at least three additional reference method test analyses until the results of six individual NO_x runs (the three original plus three additional) agree within 10 percent (or 10 ppm, whichever is greater) of the average (O_2 test results must be within 0.5 percent O_2). Then use this average for the cylinder value.

5.2 Measurement System Preparation. Prior to the emission test, assemble the measurement system following the manufacturer's written instructions in preparing and operating the NO_2 to NO converter, the NO_x analyzer, the O_2 analyzer, and other components.

Date _____ (Must be within 1 month prior to the test period)

Reference method used _____

Sample run	Gas concentration, ppm		
	Low level[a]	Mid level[b]	High level[c]
1			
2			
3			
Average			
Maximum % deviation[d]			

[a] Average must be 20 to 30% of span value.

[b] Average must be 45 to 55% of span value.

[c] Average must be 80 to 90% of span value.

[d] Must be $\leq \pm$ 10% of applicable average or 10 ppm, whichever is greater.

Figure 20-2. Analysis of calibration gases

calibration valve until all readings are stable then, switch to monitor the stack effluent until a stable reading can be obtained. Record the upscale response time. Next, introduce high-level calibration gas into the system. Once the system has stabilized at the high-level concentration, switch to monitor the stack effluent and wait until a stable value is reached. Record the downscale response time Repeat the procedure three times A stable value is equivalent to a change of less than 1 percent of span value for 30 seconds or less than 5 percent of the measured average concentration for 2 minutes Record the response time data on a form similar to Figure 20–5, the readings of the upscale or downscale reponse time, and report the greater time as the "response time" for the analyzer. Conduct a response time test prior to the initial field use of the measurement system, and repeat if changes are made in the measurement system.

Date of test _____

Analyzer type _____ S/N _____

Span gas concentration _____ ppm

Analyzer span setting _____ ppm

Upscale	1 _____	seconds
	2 _____	seconds
	3 _____	seconds
Average upscale response	_____	seconds
Downscale	1 _____	seconds
	2 _____	seconds
	3 _____	seconds
Average downscale response	_____	seconds

System response time = slower average time = _____ seconds.

Figure 20-5. Response time

5.6 NO_2-NO Conversion Efficiency Introduce to the system, at the calibration valve assembly, the NO_2/NO gas mixture (Section 4.5). Record the response of the NO_x analyzer. If the instrument response indicates less than 90 percent NO_2 to NO conversion, make corrections to the measurement system and repeat the check. Alternatively, the NO_2 to NO converter check described in Title 40 Part 86 *Certification and Test Procedures for Heavy-Duty Engines for 1979 and Later Model Years* may be used. Other alternate procedures may be used with approval of the Administrator.

6 Emission Measurement Test Procedure

6.1 Preliminaries.

6.1.1 Selection of a Sampling Site. Select a sampling site as close as practical to the exhaust of the turbine. Turbine geometry, stack configuration, internal baffling, and point of introduction of dilution air will vary for different turbine designs. Thus, each of these factors must be given special consideration in order to obtain a representative sample. Whenever possible, the sampling site shall be located upstream of the point of introduction of dilution air into the duct. Sample ports may be located before or after the upturn elbow, in order to accommodate the configuration of the turning vanes and baffles and to permit a complete, unobstructed traverse of the stack. The sample ports shall not be located within 5 feet or 2 diameters (whichever is less) of the gas discharge to atmosphere. For supplementary-fired, combined-cycle plants, the sampling site shall be located between the gas turbine and the boiler. The diameter of the sample ports shall be sufficient to allow entry of the sample probe.

6.1.2 A preliminary O_2 traverse is made for the purpose of selecting low O_2 values. Conduct this test at the turbine condition that is the lowest percentage of peak load operation included in the program. Follow the procedure below or alternative procedures subject to the approval of the Administrator may be used:

6.1.2.1 Minimum Number of Points. Select a minimum number of points as follows: (1) eight, for stacks having cross-sectional areas less than 1.5 m^2 (16.1 ft^2); (2) one sample point for each 0.2 m^2 (2.2 ft^2 of areas, for stacks of 1.5 m^2 to 10.0 m^2 (16.1–107.6 ft^2) in cross-sectional area; and (3) one sample point for each 0.4 m^2 (4.4 ft^2) of area, for stacks greater than 10.0 m^2 (107.6 ft^2) in cross-sectional area. Note that for circular ducts, the number of sample points must be a multiple of 4, and for rectangular ducts, the number of points must be one of those listed in Table 20–2; therefore, round off the number of points (upward), when appropriate

6.1.2.2 Cross-sectional Layout and Location of Traverse Points. After the number of traverse points for the preliminary O^2 sampling has been determined, use Method 1 to located the traverse points.

6.1.2.3 Preliminary O^2 Measurement. While the gas turbine is operating at the lowest percent of peak load, conduct a preliminary O^2 measurement as follows: Position the probe at the first traverse point and begin sampling. The minimum sampling time at each point shall be 1 minute plus the average system response time. Determine the average steady-state concentration of O^2 at each point and record the data on Figure 20–6.

6.1.2.4 Selection of Emission Test Sampling Points. Select the eight sampling points at which the lowest O^2 concentration were obtained. Use these same points for all the test runs at the different turbine load conditions More than eight points may be used, if desired.

Table 20-2.—*Cross-sectional Layout for Rectangular Stacks*

No. of traverse points	Matrix layout
9	3 x 3
12	4 x 3
16	4 x 4
20	5 x 4
25	5 x 5
30	6 x 5
36	6 x 6
42	7 x 6
49	7 x 7

5.3 Calibration Check. Conduct the calibration checks for both the NO_x and the O_2 analyzers as follows:

5.3.1 After the measurement system has been prepared for use (Section 5.2), introduce zero gases and the mid-level calibration gases; set the analyzer output responses to the appropriate levels. Then introduce each of the remainder of the calibration gases described in Sections 4.3 or 4.4, one at a time, to the measurement system. Record the responses on a form similar to Figure 20–3.

5.3.2 If the linear curve determined from the zero and mid-level calibration gas responses does not predict the actual response of the low-level (not applicable for the O_2 analyzer) and high-level gases within ±2 percent of the span value, the calibration shall be considered invalid. Take corrective measures on the measurement system before proceeding with the test.

5.4 Interference Response. Introduce the gaseous components listed in Table 20–1 into the measurement system separately, or as gas mixtures. Determine the total interference output response of the system to these components in concentration units; record the values on a form similar to Figure 20–4. If the sum of the interference responses of the test gases for either the NO_x or O_2 analyzers is greater than 2 percent of the applicable span value, take corrective measure on the measurement system.

Table 20–1.—*Interference Test Gas Concentration*

CO	500 ± 50 ppm
SO_2	200 ± 20 ppm.
CO_2	10 ± 1 percent
O_2	20.9 ± 1 percent.

Date of test _____

Analyzer type _____ Serial No. _____

Test gas type	Concentration (ppm)	Analyzer output response	% of span

% of span = $\frac{\text{Analyzer output response}}{\text{Instrument span}} \times 100$

Figure 20 4 Interference response

Turbine type: _____ Identification number _____

Date: _____ Test number _____

Analyzer type: _____ Identification number _____

	Cylinder value, ppm or %	Initial analyzer response, ppm or %	Final analyzer responses, ppm or %	Difference: initial-final, ppm or %
Zero gas				
Low - level gas				
Mid - level gas				
High - level gas				

$$\text{Percent drift} = \frac{\text{Absolute difference}}{\text{Span value}} \times 100.$$

Figure 20-3. Zero and calibration data.

Conduct an interference response test of each analyzer prior to its initial use in the field. Thereafter, recheck the measurement system if changes are made in the instrumentation that could alter the interference response, e.g., changes in the type of gas detector.

In lieu of conducting the interference response test, instrument vendor data, which demonstrate that for the test gases of Table 20–1 the interference performance specification is not exceeded, are acceptable.

5.5 Residence and Response Time.

5.5.1 Calculate the residence time of the sample interface portion of the measurement system using volume and pump flow rate information. Alternatively, if the response time determined as defined in Section 5.5.2 is less than 30 seconds, the calculations are not necessary.

5.5.2 To determine response time, first introduce zero gas into the system at the

Location: Date _____

Plant _____

City, State _____

Turbine identification:

Manufacturer _____

Model, serial number _____

Sample point	Oxygen concentration, ppm

Figure 20-6. Preliminary oxygen traverse.

6.2 NO_x and O_2 Measurement. This test is to be conducted at each of the specified load conditions. Three test runs at each load condition constitute a complete test.

6.2.1 At the beginning of each NO_x test run and, as applicable, during the run, record turbine data as indicated in Figure 20-7. Also, record the location and number of the traverse points on a diagram.

6.2.2 Position the probe at the first point determined in the preceding section and begin sampling. The minimum sampling time at each point shall be at least 1 minute plus the average system response time. Determine the average steady-state concentration of O_2 and NO_x at each point and record the data on Figure 20-8.

TURBINE OPERATION RECORD

Test operator _____ Date _____

Turbine identification:

Type _____ Ultimate fuel

Serial No. _____ Analysis C _____

H _____

Location: O _____

Plant _____ N _____

City _____ S _____

Ambient temperature _____ Ash _____

H_2O _____

Ambient humidity _____

Trace Metals

Test time start _____ _____

Na _____

Test time finish _____ Va _____

K _____

Fuel flow rate[a] _____ etc[b] _____

Water or steam _____ Operating load _____

Flow rate[a]

Ambient Pressure _____

[a]Describe measurement method, i.e., continuous flow meter, start finish volumes, etc.

[b]i.e., additional elements added for smoke suppression.

Figure 20-7. Stationary gas turbine data.

Turbine identification:

Manufacturer _____

Model, serial No. _____

Location:

Plant _____

City, State _____

Ambient temperature _____

Ambient pressure _____

Date _____

Test time - start _____

Test time - finish _____

Test operator name _____

O_2 instrument type _____

Serial No. _____

NO_x instrument type _____

Serial No. _____

Sample point	Time, min.	O_2^a, %	NO_x^a, ppm

[a]Average steady-state value from recorder or instrument readout.

Figure 20-8. Stationary gas turbine sample point record.

6.2.3 After sampling the last point, conclude the test run by recording the final turbine operating parameters and by determining the zero and calibration drift, as follows:

Immediately following the test run at each load condition, or if adjustments are necessary for the measurement system during the tests, reintroduce the zero and mid-level calibration gases as described in Sections 4.3, and 4.4, one at a time, to the measurement system at the calibration valve assembly. (Make no adjustments to the measurement system until after the drift checks are made). Record the analyzers' responses on a form similar to Figure 20-3. If the drift values exceed the specified limits, the test run preceding the check is considered invalid and will be repeated following corrections to the measurement system. Alternatively, the test results may be accepted provided the measurement system is recalibrated and the calibration data that result in the highest corrected emission rate are used.

6.3 SO_2 Measurement. This test is conducted only at the 100 percent peak load condition. Determine SO_2 using Method 6, or equivalent, during the test. Select a minimum of six total points from those required for the NO_x measurements; use two points for each sample run. The sample time at each point shall be at least 10 minutes. Average the O_2 readings taken during the NO_x test runs at sample points corresponding to the SO_2 traverse points (see Section 6.2.2) and use this average O_2 concentration to correct the integrated SO_2 concentration obtained by Method 6 to 15 percent O_2 (see Equation 20-1).

If the applicable regulation allows fuel sampling and analysis for fuel sulfur content to demonstrate compliance with sulfur emission unit, emission sampling with Reference Method 6 is not required, provided the fuel sulfur content meets the limits of the regulation.

7. Emission Calculations

7.1 Correction to 15 Percent Oxygen. Using Equation 20-1, calculate the NO_x and SO_2 concentrations (adjusted to 15 percent O_2). The correction to 15 percent O_2 is sensitive to the accuracy of the O_2 measurement. At the level of analyzer drift specified in the method (±2 percent of full scale), the change in the O_2 concentration correction can exceed 10 percent when the O_2 content of the exhaust is above 16 percent O_2. Therefore O_2 analyzer stability and careful calibration are necessary.

$$C_{adj} = C_{meas} \times \frac{5.9}{20.9 - \%\ O_2} \qquad \text{(Equation 20-1)}$$

Where:

C_{adj} = Pollutant concentration adjusted to 15 percent O_2 (ppm)

C_{meas} = Pollutant concentration measured, dry basis (ppm)

5.9 = 20.9 percent O_2 − 15 percent O_2, the defined O_2 correction basis

Percent O_2 = Percent O_2 measured, dry basis (%)

7.2 Calculate the average adjusted NO_x concentration by summing the point values and dividing by the number of sample points.

8. Citations

8.1 Curtis, F. A Method for Analyzing NO_x Cylinder Gases-Specific Ion Electrode Procedure, Monograph available from Emission Measurement Laboratory, ESED, Research Triangle Park, N.C. 27711, October 1978.

APPENDIX B—PERFORMANCE SPECIFICATIONS[18]

Performance Specification 1—Performance specifications and specification test procedures for transmissometer systems for continuous measurement of the opacity of stack emissions [23]

1. Principle and Applicability.

1.1 Principle. The opacity of particulate matter in stack emissions is measured by a continuously operating emission measurement system. These systems are based upon the principle of transmissometry which is a direct measurement of the attenuation of visible radiation (opacity) by particulate matter in a stack effluent. Light having specific spectral characteristics is projected from a lamp across the stack of a pollutant source to a light sensor. The light is attenuated due to absorption and scatter by the particulate matter in the effluent. The percentage of visible light attenuated is defined as the opacity of the emission. Transparent stack emissions that do not attenuate light will have a transmittance of 100 or an opacity of 0. Opaque stack emissions that attenuate all of the visible light will have a transmittance of 0 or an opacity of 100 percent. The transmissometer is evaluated by use of neutral density filters to determine the precision of the continuous monitoring system. Tests of the system are performed to determine zero drift, calibration drift, and response time characteristics of the system.

1.2 Applicability. This performance specification is applicable to the continuous monitoring systems specified in the subparts for measuring opacity of emissions. Specifications for continuous measurement of visible emissions are given in terms of design, performance, and installation parameters. These specifications contain test procedures, installation requirements, and data computation procedures for evaluating the acceptability of the continuous monitoring systems subject to approval by the Administrator.

2. Apparatus.

2.1 Calibrated Filters. Optical filters with neutral spectral characteristics and known optical densities to visible light or screens known to produce specified optical densities. Calibrated filters with accuracies certified by the manufacturer to within ±3 percent opacity shall be used. Filters required are low, mid, and high-range filters with nominal optical densities as follows when the transmissometer is spanned at opacity levels specified by applicable subparts:

Span value (percent opacity)	Calibrated filter optical densities with equivalent opacity in parenthesis		
	Low-range	Mid-range	High-range
50	0.1 (20)	0.2 (37)	0.3 (50)
60	.1 (20)	.2 (37)	.3 (50)
70	.1 (20)	.3 (50)	.5 (68)
80	.1 (20)	.3 (50)	.6 (75)
90	.1 (20)	.4 (60)	.7 (80)
100	.1 (20)	.4 (60)	.9 (87½)

It is recommended that filter calibrations be checked with a well-collimated photopic transmissometer of known linearity prior to use. The filters shall be of sufficient size to attenuate the entire light beam of the transmissometer.

2.2 Data Recorder. Analog chart recorder or other suitable device with input voltage range compatible with the analyzer system output. The resolution of the recorder's data output shall be sufficient to allow completion of the test procedures within this specification. [23]

2.3 Opacity measurement System. An in-stack transmissometer (folded or single path) with the optical design specifications designated below, associated control units and apparatus to keep optical surfaces clean.

3. Definitions.

3.1 Continuous Monitoring System. The total equipment required for the determination of pollutant opacity in a source effluent. Continuous monitoring systems consist of major subsystems as follows:

3.1.1 Sampling Interface. The portion of a continuous monitoring system for opacity that protects the analyzer from the effluent.

3.1.2 Analyzer. That portion of the continuous monitoring system which senses the pollutant and generates a signal output that is a function of the pollutant opacity.

3.1.3 Data Recorder. That portion of the continuous monitoring system that processes the analyzer output and provides a permanent record of the output signal in terms of pollutant opacity.

3.2 Transmissometer. The portions of a continuous monitoring system for opacity that include the sampling interface and the analyzer.

3.3 Span. The value of opacity at which the continuous monitoring system is set to produce the maximum data display output. The span shall be set at an opacity specified in each applicable subpart.

3.4 Calibration Error. The difference between the opacity reading indicated by the continuous monitoring system and the known values of a series of test standards. For this method the test standards are a series of calibrated optical filters or screens.

3.5 Zero Drift. The change in continuous monitoring system output over a stated period of time of normal continuous operation when the pollutant concentration at the time of the measurements is zero.

3.6 Calibration Drift. The change in the continuous monitoring system output over a stated period of time of normal continuous operation when the pollutant concentration at the time of the measurements is the same known upscale value.

3.7 System Response. The time interval from a step change in opacity in the stack at the input to the continuous monitoring system to the time at which 95 percent of the corresponding final value is reached as displayed on the continuous monitoring system data recorder.

3.8 Operational Test Period. A minimum period of time over which a continuous monitoring system is expected to operate within certain performance specifications without unscheduled maintenance, repair, or adjustment.

3.9 Transmittance. The fraction of incident light that is transmitted through an optical medium of interest.

3.10 Opacity. The fraction of incident light that is attenuated by an optical medium of interest. Opacity (O) and transmittance (T) are related as follows:

$$O = 1 - T$$

3.11 Optical Density. A logarithmic measure of the amount of light that it attenuated by an optical medium of interest. Optical density (D) is related to the transmittance and opacity as follows.

$$D = -\log_{10} T$$

$$D = -\log_{10} (1-0)$$

3.12 Peak Optical Response. The wavelength of maximum sensitivity of the instrument.

3.13 Mean Spectral Response. The wavelength which bisects the total area under the curve obtained pursuant to paragraph 9.2.1.

3.14 Angle of View. The maximum (total) angle of radiation detection by the photodetector assembly of the analyzer.

3.15 Angle of Projection. The maximum (total) angle that contains 95 percent of the radiation projected from the lamp assembly of the analyzer.

3.16 Pathlength. The depth of effluent in the light beam between the receiver and the transmitter of the single-pass transmissometer, or the depth of effluent between the transceiver and reflector of a double-pass transmissometer. Two pathlengths are referenced by this specification:

3.16.1 Monitor Pathlength. The depth of effluent at the installed location of the continuous monitoring system.

3.16.2 Emission Outlet Pathlength. The depth of effluent at the location emissions are released to the atmosphere.

4. Installation Specification.

4.1 Location. The transmissometer must be located across a section of duct or stack that will provide a particulate matter flow through the optical volume of the transmissometer that is representative of the particulate matter flow through the duct or stack. It is recommended that the monitor pathlength or depth of effluent for the transmissometer include the entire diameter of the duct or stack. In installations using a shorter pathlength, extra caution must be used in determining the measurement location representative of the particulate matter flow through the duct or stack.

4.1.1 The transmissometer location shall be downstream from all particulate control equipment.

4.1.2 The transmissometer shall be located as far from bends and obstructions as practical.

4.1.3 A transmissometer that is located in the duct or stack following a bend shall be installed in the plane defined by the bend where possible.

4.1.4 The transmissometer should be installed in an accessible location.

4.1.5 When required by the Administrator, the owner or operator of a source must demonstrate that the transmissometer is located in a section of duct or stack where a representative particulate matter distribution exists. The determination shall be accomplished by examining the opacity profile of the effluent at a series of positions across the duct or stack while the plant is in operation at maximum or reduced operating rates or by other tests acceptable to the Administrator.

4.2 Slotted Tube Installations that require the use of a slotted tube shall use a slotted tube of sufficient size and blackness so as not to interfere with the free flow of effluent through the entire optical volume of the transmissometer or reflect light into the transmissometer photodetector. Light reflections may be prevented by using blackened baffles within the slotted tube to prevent the lamp radiation from impinging upon the tube walls, by restricting the angle of projection of the light and the angle of view of the photodetector assembly to less than the cross-sectional area of the slotted tube, or by other methods. The owner or operator must show that the manufacturer of the monitoring system has used appropriate methods to minimize light reflections for systems using slotted tubes.

4.3 Data Recorder Output. The continuous monitoring system output shall permit expanded display of the span opacity on a standard 0 to 100 percent scale. Since all opacity standards are based on the opacity of the effluent exhausted to the atmosphere, the system output shall be based upon the emission outlet pathlength and permanently recorded. For affected facilities whose monitor pathlength is different from the facility's emission outlet pathlength, a graph shall be provided with the installation to show the relationships between the continuous monitoring system recorded opacity based upon the emission outlet pathlength and the opacity of the effluent at the analyzer location (monitor pathlength). Tests for measurement of opacity that are required by this performance specification are based upon the

monitor pathlength. The graph necessary to convert the data recorder output to the monitor pathlength-basis shall be established as follows:

$$\log (1-0_1) = (l_1/l_2) \log (1-0_2)$$

where:

0_1 = the opacity of the effluent based upon l_1.

0_2 = the opacity of the effluent based upon l_2.

l_1 = the emission outlet pathlength.

l_2 = the monitor pathlength.

5. Optical Design Specifications.

The optical design specifications set forth in Section 6.1 shall be met in order for a measurement system to comply with the requirements of this method

6. Determination of Conformance with Design Specifications.

6.1 The continuous monitoring system for measurement of opacity shall be demonstrated to conform to the design specifications set forth as follows:

6.1.1 Peak Spectral Response. The peak spectral response of the continuous monitoring systems shall occur between 500 nm and 600 nm. Response at any wavelength below 400 nm or above 700 nm shall be less than 10 percent of the peak response of the continuous monitoring system.

6.1.2 Mean Spectral Response. The mean spectral response of the continuous monitoring system shall occur between 500 nm and 600 nm.

6.1.3 Angle of View. The total angle of view shall be no greater than 5 degrees.

6.1.4 Angle of Projection The total angle of projection shall be no greater than 5 degrees.

6.2 Conformance with the requirements of section 6.1 may be demonstrated by the owner or operator of the affected facility by testing each analyzer or by obtaining a certificate of conformance from the instrument manufacturer. The certificate must certify that at least one analyzer from each month's production was tested and satisfactorily met all applicable requirements. The certificate must state that the first analyzer randomly sampled met all requirements of paragraph 6 of this specification. If any of the requirements were not met, the certificate must show that the entire month's analyzer production was resampled according to the military standard 105D sampling procedure (MIL–STD–105D) inspection level II; was retested for each of the applicable requirements under paragraph 6 of this specification; and was determined to be acceptable under MIL–STD–105D procedures The certificate of conformance must show the results of each test performed for the analyzers sampled during the month the analyzer being installed was produced. [57]

6.3 The general test procedures to be followed to demonstrate conformance with Section 6 requirements are given as follows (These procedures will not be applicable to all designs and will require modification in some cases. Where analyzer and optical design is certified by the manufacturer to conform with the angle of view or angle of projection specifications, the respective procedures may be omitted.)

6.3.1 Spectral Response. Obtain spectral data for detector, lamp, and filter components used in the measurement system from their respective manufacturers

6.3.2 Angle of View. Set the received up as specified by the manufacturer. Draw an arc with radius of 3 meters. Measure the receiver response to a small (less than 3 centimeters) non-directional light source at 5-centimeter intervals on the arc for 26 centimeters on either side of the detector centerline. Repeat the test in the vertical direction.

6.3.3 Angle of Projection. Set the projector up as specified by the manufacturer. Draw an arc with radius of 3 meters. Using a small photoelectric light detector (less than 3 centimeters), measure the light intensity at 5-centimeter intervals on the arc for 26 centimeters on either side of the light source centerline of projection. Repeat the test in the vertical direction.

7 Continuous Monitoring System Performance Specifications

The continuous monitoring system shall meet the performance specifications in Table 1–1 to be considered acceptable under this method

TABLE 1–1.—*Performance specifications*

Parameter	*Specifications*
a. Calibration error	≤3 pct opacity [1]
b Zero drift (24 h)	≤2 pct opacity [1]
c. Calibration drift (24 h)	≤2 pct opacity [1]
d Response time	10 s (maximum)
e. Operational test period	168 h.

[1] Expressed as sum of absolute mean value and the 95 pct confidence interval of a series of tests

8. Performance Specification Test Procedures. The following test procedures shall be used to determine conformance with the requirements of paragraph 7:

8.1 Calibration Error and Response Time Test. These tests are to be performed prior to installation of the system on the stack and may be performed at the affected facility or at other locations provided that proper notification is given. Set up and calibrate the measurement system as specified by the manufacturer's written instructions for the monitor pathlength to be used in the installation. Span the analyzer as specified in applicable subparts.

8.1.1 Calibration Error Test. Insert a series of calibration filters in the transmissometer path at the midpoint A minimum of three calibration filters (low, mid, and high-range) selected in accordance with the table under paragraph 2.1 and calibrated within 3 percent must be used. Make a total of five nonconsecutive readings for each filter **Record the measurement system output** readings in percent opacity. (See Figure 1–1.)

8.1.2 System Response Test. Insert the high-range filter in the transmissometer path five times and record the time required for the system to respond to 95 percent of final zero and high-range filter values. (See Figure 1–2.)

8.2 Field Test for Zero Drift and Calibration Drift. Install the continuous monitoring system on the affected facility and perform the following alignments:

8.2.1 Preliminary Alignments. As soon as possible after installation and once a year thereafter when the facility is not in operation, perform the following optical and zero alignments:

8.2.1.1 Optical Alignment. Align the light beam from the transmissometer upon the optical surfaces located across the effluent (i.e., the retroflector or photodetector as applicable) in accordance with the manufacturer's instructions.

8.2.1.2 Zero Alignment. After the transmissometer has been optically aligned and the transmissometer mounting is mechanically stable (i.e., no movement of the mounting due to thermal contraction of the stack, duct, etc.) and a clean stack condition has been determined by a steady zero opacity condition, perform the zero alignment. This alignment is performed by balancing the continuous monitor system response so that any simulated zero check coincides with an actual zero check performed across the monitor pathlength of the clean stack.

8.2.1.3 Span. Span the continuous monitoring system at the opacity specified in subparts and offset the zero setting at least 10 percent of span so that negative drift can be quantified.

8.2.2. Final Alignments. After the preliminary alignments have been completed and the affected facility has been started up and reaches normal operating temperature, recheck the optical alignment in accordance with 8.2.1.1 of this specification. If the alignment has shifted, realign the optics, record any detectable shift in the opacity measured by the system that can be attributed to the optical realignment, and notify the Administrator. This condition may not be objectionable if the affected facility operates within a fairly constant and adequately narrow range of operating temperatures that does not produce significant shifts in optical alignment during normal operation of the facility. Under circumstances where the facility operations produce fluctuations in the effluent gas temperature that result in significant misalignments, the Administrator may require improved mounting structures or another location for installation of the transmissometer.

8.2.3 Conditioning Period. After completing the post-startup alignments, operate the system for an initial 168-hour conditioning period in a normal operational manner.

8.2.4 Operational Test Period. After completing the conditioning period, operate the system for an additional 168-hour period retaining the zero offset. The system shall monitor the source effluent at all times except when being zeroed or calibrated. At 24-hour intervals the zero and span shall be checked according to the manufacturer's instructions. Minimum procedures used shall provide a system check of the analyzer internal mirrors and all electronic circuitry including the lamp and photodetector assembly and shall include a procedure for producing a simulated zero opacity condition and a simulated upscale (span) opacity condition as viewed by the receiver. The manufacturer's written instructions may be used providing that they equal or exceed these minimum procedures. Zero and span the transmissometer, clean all optical surfaces exposed to the effluent, realign optics, and make any necessary adjustments to the calibration of the system daily. These zero and calibration adjustments and optical realignments are allowed only at 24-hour intervals or at such shorter intervals as the manufacturer's written instructions specify. Automatic corrections made by the measurement system without operator intervention are allowable at any time. The magnitude of any zero or span drift adjustments shall be recorded. During this 168-hour operational test period, record the following at 24-hour intervals: (a) the zero reading and span readings after the system is calibrated (these readings should be set at the same value at the beginning of each 24-hour period); (b) the zero reading after each 24 hours of operation, but before cleaning and adjustment; and (c) the span reading after cleaning and zero adjustment, but before span adjustment. (See Figure 1–3.)

9. Calculation, Data Analysis, and Reporting.

9.1 Procedure for Determination of Mean Values and Confidence Intervals.

9.1.1 The mean value of the data set is calculated according to equation 1–1.

$$\bar{x} = \frac{1}{n} \sum_{i=1}^{n} x_i \qquad \text{Equation 1–1}$$

where x_i = absolute value of the individual measurements,

Σ = sum of the individual values.

$\bar{x}$ = mean value, and

n = number of data points. [23]

9.1.2 The 95 percent confidence interval (two-sided) is calculated according to equation 1–2:

$$C.I._{.95} = \frac{t_{.975}}{n\sqrt{n-1}} \sqrt{n(\Sigma x_i^2) - (\Sigma x_i)^2} \qquad \text{Equation 1–2}$$

where

Σx_i = sum of all data points,

$t_{.975} = t_{1-\alpha/2}$, and

$C.I._{.95}$ = 95 percent confidence interval estimate of the average mean value.

The values in this table are already corrected for n-1 degrees of freedom. Use n equal to the number of samples as data points.

Values for t.975

n	t.975	n	t.975
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

9.2 Data Analysis and Reporting.

9.2.1 Spectral Response. Combine the spectral data obtained in accordance with paragraph 6.3.1 to develop the effective spectral response curve of the transmissometer. Report the wavelength at which the peak response occurs, the wavelength at which the mean response occurs, and the maximum response at any wavelength below 400 nm and above 700 nm expressed as a percentage of the peak response as required under paragraph 6.2.

9.2.2 Angle of View. Using the data obtained in accordance with paragraph 6.3.2, calculate the response of the receiver as a function of viewing angle in the horizontal and vertical directions (26 centimeters of arc with a radius of 3 meters equal 5 degrees). Report relative angle of view curves as required under paragraph 6.2.

9.2.3 Angle of Projection. Using the data obtained in accordance with paragraph 6.3.3, calculate the response of the photoelectric detector as a function of projection angle in the horizontal and vertical directions. Report relative angle of projection curves as required under paragraph 6.2.

9.2.4 Calibration Error. Using the data from paragraph 8.1 (Figure 1-1), subtract the known filter opacity value from the value shown by the measurement system for each of the 15 readings. Calculate the mean and 95 percent confidence interval of the five different values at each test filter value according to equations 1-1 and 1-2. Report the sum of the absolute mean difference and the 95 percent confidence interval for each of the three test filters.

Low Range ___% opacity Span Value ___% opacity

Mid Range ___% opacity

High Range ___% opacity

Date of Test _____ Location of Test _____

Calibrated Filter	Analyzer Reading % Opacity	Differences[2] % Opacity
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		

	Low	Mid	High
Mean difference	___	___	___
Confidence interval	___	___	___
Calibration error = Mean Difference[3] + C.I.	___	___	___

[1] Low, mid or high range

[2] Calibration filter opacity - analyzer reading

[3] Absolute value

Figure 1-1. Calibration Error Test

Date of Test _____ Location of Test _____

Span Filter _____ % Opacity

Analyzer Span Setting _____ % Opacity

Upscale 1 _____ seconds
2 _____ seconds
3 _____ seconds
4 _____ seconds
5 _____ seconds

Downscale 1 _____ seconds
2 _____ seconds
3 _____ seconds
4 _____ seconds
5 _____ seconds

Average response _____ seconds

Figure 1-2. Response Time Test

9.2.5 Zero Drift. Using the zero opacity values measured every 24 hours during the field test (paragraph 8.2), calculate the differences between the zero point after cleaning, aligning, and adjustment, and the zero value 24 hours later just prior to cleaning, aligning, and adjustment. Calculate the mean value of these points and the confidence interval using equations 1-1 and 1-2. Report the sum of the absolute mean value and the 95 percent confidence interval.

9.2.6 Calibration Drift. Using the span value measured every 24 hours during the field test, calculate the differences between the span value after cleaning, aligning, and adjustment of zero and span, and the span value 24 hours later just after cleaning, aligning, and adjustment of zero and before adjustment of span. Calculate the mean value of these points and the confidence interval using equations 1-1 and 1-2. Report the sum of the absolute mean value and the confidence interval.

9.2.7 Response Time. Using the data from paragraph 8.1, calculate the time interval from filter insertion to 95 percent of the final stable value for all upscale and downscale traverses. Report the mean of the 10 upscale and downscale test times.

9.2.8 Operational Test Period. During the 168-hour operational test period, the continuous monitoring system shall not require any corrective maintenance, repair, replacement, or adjustment other than that clearly specified as required in the manufacturer's operation and maintenance manuals as routine and expected during a one-week period. If the continuous monitoring system is operated within the specified performance parameters and does not require corrective maintenance, repair, replacement, or adjustment other than as specified above during the 168-hour test period, the operational test period shall have been successfully concluded. Failure of the continuous monitoring system to meet these requirements shall call for a repetition of the 168-hour test period. Portions of the tests which were satisfactorily completed need not be repeated. Failure to meet any performance specification(s) shall call for a repetition of the one-week operational test period and that specific portion of the tests required by paragraph 8 related to demonstrating compliance with the failed specification. All maintenance and adjustments required shall be recorded. Output readings shall be recorded before and after all adjustments.

10. References.

10.1 "Experimental Statistics," Department of Commerce, National Bureau of Standards Handbook 91, 1963, pp. 3-31, paragraphs 3-3.1.4.

10.2 "Performance Specifications for Stationary-Source Monitoring Systems for Gases and Visible Emissions," Environmental Protection Agency, Research Triangle Park, N.C., EPA-650/2-74-013, January 1974.

Zero Setting _____ (See paragraph 8.2.1) Date of Test _____

Span Setting _____

Date and Time	Zero Reading (Before cleaning and adjustment)	Zero Drift (Δzero)	Span Reading (After cleaning and zero adjustment but before span adjustment)	Calibration Drift (ΔSpan)

Zero Drift = Mean Zero Drift* _____ + CI (Zero) _____ = _____.

Calibration Drift = Mean Span Drift* _____ + CI (Span) _____ = _____.

*Absolute value

PERFORMANCE SPECIFICATION 2—PERFORMANCE SPECIFICATIONS AND SPECIFICATION TEST PROCEDURES FOR MONITORS OF SO_2 AND NO_x FROM STATIONARY SOURCES

1 Principle and Applicability.

1.1 Principle. The concentration of sulfur dioxide or oxides of nitrogen pollutants in stack emissions is measured by a continuously operating emission measurement system. Concurrent with operation of the continuous monitoring system, the pollutant concentrations are also measured with reference methods (Appendix A). An average of the continuous monitoring system data is computed for each reference method testing period and compared to determine the relative accuracy of the continuous monitoring system. Other tests of the continuous monitoring system are also performed to determine calibration error, drift, and response characteristics of the system.

1.2 Applicability. This performance specification is applicable to evaluation of continuous monitoring systems for measurement of nitrogen oxides or sulfur dioxide pollutants These specifications contain test procedures, installation requirements, and data computation procedures for evaluating the acceptability of the continuous monitoring systems.

2. Apparatus.

2 1 Calibration Gas Mixtures. Mixtures of known concentrations of pollutant gas in a diluent gas shall be prepared. The pollutant gas shall be sulfur dioxide or the appropriate oxide(s) of nitrogen specified by paragraph 6 and within subparts For sulfur dioxide gas mixtures, the diluent gas may be air or nitrogen For nitric oxide (NO) gas mixtures, the diluent gas shall be oxygen-free (<10 ppm) nitrogen, and for nitrogen dioxide (NO_2) gas mixtures the diluent gas shall be air. Concentrations of approximately 50 percent and 90 percent of span are required. The 90 percent gas mixture is used to set and to check the span and is referred to as the span gas.

2.2 Zero Gas. A gas certified by the manufacturer to contain less than 1 ppm of the pollutant gas or ambient air may be used.

2 3 Equipment for measurement of the pollutant gas concentration using the reference method specified in the applicable standard.

2 4 Data Recorder. Analog chart recorder or other suitable device with input voltage range compatible with analyzer system output The resolution of the recorder's data output shall be sufficient to allow completion of the test procedures within this specification.

2.5 Continuous monitoring system for SO_2 or NO_x pollutants as applicable.

3. Definitions

3.1 Continuous Monitoring System. The total equipment required for the determination of a pollutant gas concentration in a source effluent. Continuous monitoring systems consist of major subsystems as follows:

3.1.1 Sampling Interface—That portion of an extractive continuous monitoring system that performs one or more of the following operations: acquisition, transportation, and conditioning of a sample of the source effluent or that portion of an in-situ continuous monitoring system that protects the analyzer from the effluent.

3.1.2 Analyzer—That portion of the continuous monitoring system which senses the pollutant gas and generates a signal output that is a function of the pollutant concentration

3.1.3 Data Recorder—That portion of the continuous monitoring system that provides a permanent record of the output signal in terms of concentration units

3.2 Span. The value of pollutant concentration at which the continuous monitoring system is set to produce the maximum data display output. The span shall be set at the concentration specified in each applicable subpart

3.3 Accuracy (Relative). The degree of correctness with which the continuous monitoring system yields the value of gas concentration of a sample relative to the value given by a defined reference method. This accuracy is expressed in terms of error, which is the difference between the paired concentration measurements expressed as a percentage of the mean reference value.

3.4 Calibration Error. The difference between the pollutant concentration indicated by the continuous monitoring system and the known concentration of the test gas mixture.

3.5 Zero Drift. The change in the continuous monitoring system output over a stated period of time of normal continuous operation when the pollutant concentration at the time for the measurements is zero.

3 6 Calibration Drift The change in the continuous monitoring system output over a stated time period of normal continuous operations when the pollutant concentration at the time of the measurements is the same known upscale value.

3.7 Response Time. The time interval from a step change in pollutant concentration at the input to the continuous monitoring system to the time at which 95 percent of the corresponding final value is reached as displayed on the continuous monitoring system data recorder.

3 8 Operational Period A minimum period of time over which a measurement system is expected to operate within certain performance specifications without unscheduled maintenance, repair, or adjustment.

3 9 Stratification. A condition identified by a difference in excess of 10 percent between the average concentration in the duct or stack and the concentration at any point more than 1.0 meter from the duct or stack wall.

4 Installation Specifications. Pollutant continuous monitoring systems (SO_2 and NO_x) shall be installed at a sampling location where measurements can be made which are directly representative (4 1), or which can be corrected so as to be representative (4 2) of the total emissions from the affected facility. Conformance with this requirement shall be accomplished as follows:

4 1 Effluent gases may be assumed to be nonstratified if a sampling location eight or more stack diameters (equivalent diameters) downstream of any air in-leakage is selected. This assumption and data correction procedures under paragraph 4.2 1 may not be applied to sampling locations upstream of an air preheater in a steam generating facility under Subpart D of this part. For sampling locations where effluent gases are either demonstrated (4 3) or may be assumed to be nonstratified (eight diameters), a point (extractive systems) or path (in-situ systems) of average concentration may be monitored. [23]

4 2 For sampling locations where effluent gases cannot be assumed to be nonstratified (less than eight diameters) or have been shown under paragraph 4.3 to be stratified, results obtained must be consistently representative (e.g. a point of average concentration may shift with load changes) or the data generated by sampling at a point (extractive systems) or across a path (in-situ systems) must be corrected (4.2.1 and 4 2 2) so as to be representative of the total emissions from the affected facility. Conformance with this requirement may be accomplished in either of the following ways

4 2 1 Installation of a diluent continuous monitoring system (O_2 or CO_2 as applicable) in accordance with the procedures under paragraph 4 2 of Performance Specification 3 of this appendix. If the pollutant and diluent monitoring systems are not of the same type (both extractive or both in-situ), the extractive system must use a multipoint probe.

4 2 2 Installation of extractive pollutant monitoring systems using multipoint sampling probes or in-situ pollutant monitoring systems that sample or view emissions which are consistently representative of the total emissions for the entire cross section. The Administrator may require data to be sub-

mitted to demonstrate that the emissions sampled or viewed are consistently representative for several typical facility process operating conditions.

4.3 The owner or operator may perform a traverse to characterize any stratification of effluent gases that might exist in a stack or duct. If no stratification is present, sampling procedures under paragraph 4.1 may be applied even though the eight diameter criteria is not met.

4.4 When single point sampling probes for extractive systems are installed within the stack or duct under paragraphs 4.1 and 4.2.1, the sample may not be extracted at any point less than 1.0 meter from the stack or duct wall. Multipoint sampling probes installed under paragraph 4.2.2 may be located at any points necessary to obtain consistently representative samples.

5. Continuous Monitoring System Performance Specifications.

The continuous monitoring system shall meet the performance specifications in Table 2–1 to be considered acceptable under this method.

TABLE 2–1.—*Performance specifications*

Parameter	*Specification*
1. Accuracy [1]	≤20 pct of the mean value of the reference method test data.
2. Calibration error [1]	≤ 5 pct of each (50 pct, 90 pct) calibration gas mixture value.
3. Zero drift (2 h) [1]	2 pct of span
4. Zero drift (24 h) [1]	Do.
5. Calibration drift (2 h) [1]	Do.
6. Calibration drift (24 h) [1]	2.5 pct. of span
7. Response time	15 min maximum.
8. Operational period	168 h minimum.

[1] Expressed as sum of absolute mean value plus 95 pct confidence interval of a series of tests.

6. Performance Specification Test Procedures. The following test procedures shall be used to determine conformance with the requirements of paragraph 5. For NO_x an*requirements of paragraph 5. For* NO_x analyzers that oxidize nitric oxide (NO) to nitrogen dioxide (NO_2), the response time test under paragraph 6.3 of this method shall be performed using nitric oxide (NO) span gas. Other tests for NO_x continuous monitoring systems under paragraphs 6.1 and 6.2 and all tests for sulfur dioxide systems shall be performed using the pollutant span gas specified by each subpart.

6.1 Calibration Error Test Procedure. Set up and calibrate the complete continuous monitoring system according to the manufacturer's writen instructions. This may be accomplished either in the laboratory or in the field.

6.1.1 Calibration Gas Analyses. Triplicate analyses of the gas mixtures shall be performed within two weeks prior to use using Reference Methods 6 for SO_2 and 7 for NO_x. Analyze each calibration gas mixture (50%, 90%) and record the results on the example sheet shown in Figure 2–1. Each sample test result must be within 20 percent of the averaged result or the tests shall be repeated. This step may be omitted for non-extractive monitors where dynamic calibration gas mixtures are not used (6.1.2)

6.1.2 Calibration Error Test Procedure. Make a total of 15 nonconsecutive measurements by alternately using zero gas and each calibration gas mixture concentration (e.g., 0%, 50%, 0%, 90%, 50%, 90%, 50%, 0%, etc.). For nonextractive continuous monitoring systems, this test procedure may be performed by using two or more calibration gas cells whose concentrations are certified by the manufacturer to be functionally equivalent to these gas concentrations. Convert the continuous monitoring system output readings to ppm and record the results on the example sheet shown in Figure 2–2.

6.2 Field Test for Accuracy (Relative), Zero Drift, and Calibration Drift. Install and operate the continuous monitoring system in accordance with the manufacturer's written instructions and drawings as follows:

6.2.1 Conditioning Period. Offset the zero setting at least 10 percent of the span so that negative zero drift can be quantified. Operate the system for an initial 168-hour conditioning period in normal operating manner.

6.2.2 Operational Test Period. Operate the continuous monitoring system for an additional 168-hour period retaining the zero offset. The system shall monitor the source effluent at all times except when being zeroed, calibrated, or backpurged.

6.2.2.1 Field Test for Accuracy (Relative). For continuous monitoring systems employing extractive sampling, the probe tip for the continuous monitoring system and the probe tip for the Reference Method sampling train should be placed at adjacent locations in the duct. For NO_x continuous monitoring systems, make 27 NO_x concentration measurements, divided into nine sets, using the applicable reference method. No more than one set of tests, consisting of three individual measurements, shall be performed in any one hour. All individual measurements of each set shall be performed concurrently, or within a three-minute interval and the results averaged. For SO_2 continuous monitoring systems, make nine SO_2 concentration measurements using the applicable reference method. No more than one measurement shall be performed in any one hour. Record the reference method test data and the continuous monitoring system concentrations on the example data sheet shown in Figure 2–3.

6.2.2.2 Field Test for Zero Drift and Calibration Drift. For extractive systems, determine the values given by zero and span gas pollutant concentrations at two-hour intervals until 15 sets of data are obtained. For nonextractive measurement systems, the zero value may be determined by mechanically producing a zero condition that provides a system check of the analyzer internal mirrors and all electronic circuitry including the radiation source and detector assembly or by inserting three or more calibration gas cells and computing the zero point from the upscale measurements. If this latter technique is used, a graph(s) must be retained by the owner or operator for each measurement system that shows the relationship between the upscale measurements and the zero point. The span of the system shall be checked by using a calibration gas cell certified by the manufacturer to be functionally equivalent to 50 percent of span concentration. Record the zero and span measurements (or the computed zero drift) on the example data sheet shown in Figure 2–4. The two-hour periods over which measurements are conducted need not be consecutive but may not overlap. All measurements required under this paragraph may be conducted concurrent with tests under paragraph 6.2.2.1.

6.2.2.3 Adjustments. Zero and calibration corrections and adjustments are allowed only at 24-hour intervals or at such shorter intervals as the manufacturer's written instructions specify. Automatic corrections made by the measurement system without operator intervention or initiation are allowable at any time. During the entire 168-hour operational test period, record on the example sheet shown in Figure 2–5 the values given by zero and span gas pollutant concentrations *before and after adjustment* at 24-hour intervals.

6.3 Field Test for Response Time.

6.3.1 Scope of Test. Use the entire continuous monitoring system as installed, including sample transport lines if used. Flow rates, line diameters, pumping rates, pressures (do not allow the pressurized calibration gas to change the normal operating pressure in the sample line), etc., shall be at the nominal values for normal operation as specified in the manufacturer's written instructions. If the analyzer is used to sample more than one pollutant source (stack), repeat this test for each sampling point.

6.3.2 Response Time Test Procedure. Introduce zero gas into the continuous monitoring system sampling interface or as close to the sampling interface as possible. When the system output reading has stabilized, switch quickly to a known concentration of pollutant gas. Record the time from concentration switching to 95 percent of final stable response. For non-extractive monitors, the highest available calibration gas concentration shall be switched into and out of the sample path and response times recorded. Perform this test sequence three (3) times. Record the results of each test on the example sheet shown in Figure 2–6.

7. Calculations, Data Analysis and Reporting.

7.1 Procedure for determination of mean values and confidence intervals.

7.1.1 The mean value of a data set is calculated according to equation 2–1.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i \qquad \text{Equation 2-1}$$

where:

x_i = absolute value of the measurements,
Σ = sum of the individual values,
$\bar{x}$ = mean value, and
n = number of data points. 23

7.1.2 The 95 percent confidence interval (two-sided) is calculated according to equation 2–2:

$$C.I._{95} = \frac{t_{.975}}{n\sqrt{n-1}}\sqrt{n(\Sigma x_i^2) - (\Sigma x_i)^2} \qquad \text{Equation 2-2}$$

where:

Σx_i = sum of all data points,
$t_{.975} = t_f - \alpha/2$, and
$C.I._{95}$ = 95 percent confidence interval estimate of the average mean value. 23

Values for $t_{.975}$

n	$t_{.975}$
2	12.706
3	4.303
4	3.182
5	2.776
6	2.571
7	2.447
8	2.365
9	2.306
10	2.262
11	2.228
12	2.201
13	2.179
14	2.160
15	2.145
16	2.131

The values in this table are already corrected for n–1 degrees of freedom. Use n

equal to the number of samples as data points.

7.2 Data Analysis and Reporting.

7.2.1 Accuracy (Relative). For each of the nine reference method test points, determine the average pollutant concentration reported by the continuous monitoring system. These average concentrations shall be determined from the continuous monitoring system data recorded under 7.2.2 by integrating or averaging the pollutant concentrations over each of the time intervals concurrent with each reference method testing period. Before proceeding to the next step, determine the basis (wet or dry) of the continuous monitoring system data and reference method test data concentrations. If the bases are not consistent, apply a moisture correction to either reference method concentrations or the continuous monitoring system concentrations as appropriate. Determine the correction factor by moisture tests concurrent with the reference method testing periods. Report the moisture test method and the correction procedure employed. For each of the nine test runs determine the difference for each test run by subtracting the respective reference method test concentrations (use average of each set of three measurements for NO_x) from the continuous monitoring system integrated or averaged concentrations. Using these data, compute the mean difference and the 95 percent confidence interval of the differences (equations 2-1 and 2-2). Accuracy is reported as the sum of the absolute value of the mean difference and the 95 percent confidence interval of the differences expressed as a percentage of the mean reference method value. Use the example sheet shown in Figure 2-3.

7.2.2 Calibration Error. Using the data from paragraph 6.1, subtract the measured pollutant concentration determined under paragraph 6.1.1 (Figure 2-1) from the value shown by the continuous monitoring system for each of the five readings at each concentration measured under 6.1.2 (Figure 2-2). Calculate the mean of these difference values and the 95 percent confidence intervals according to equations 2-1 and 2-2. Report the calibration error (the sum of the absolute value of the mean difference and the 95 percent confidence interval) as a percentage of each respective calibration gas concentration. Use example sheet shown in Figure 2-2.

7.2.3 Zero Drift (2-hour). Using the zero concentration values measured each two hours during the field test, calculate the differences between consecutive two-hour readings expressed in ppm. Calculate the mean difference and the confidence interval using equations 2-1 and 2-2. Report the zero drift as the sum of the absolute mean value and the confidence interval as a percentage of span. Use example sheet shown in Figure 2-4.

7.2.4 Zero Drift (24-hour). Using the zero concentration values measured every 24 hours during the field test, calculate the differences between the zero point after zero adjustment and the zero value 24 hours later just prior to zero adjustment. Calculate the mean value of these points and the confidence interval using equations 2-1 and 2-2. Report the zero drift (the sum of the absolute mean and confidence interval) as a percentage of span. Use example sheet shown in Figure 2-5.

7.2.5 Calibration Drift (2-hour). Using the calibration values obtained at two-hour intervals during the field test, calculate the differences between consecutive two-hour readings expressed as ppm. These values should be corrected for the corresponding zero drift during that two-hour period. Calculate the mean and confidence interval of these corrected difference values using equations 2-1 and 2-2. Do not use the differences between non-consecutive readings. Report the calibration drift as the sum of the absolute mean and confidence interval as a percentage of span. Use the example sheet shown in Figure 2-4.

7.2.6 Calibration Drift (24-hour). Using the calibration values measured every 24 hours during the field test, calculate the differences between the calibration concentration reading after zero and calibration adjustment, and the calibration concentration reading 24 hours later after zero adjustment but before calibration adjustment. Calculate the mean value of these differences and the confidence interval using equations 2-1 and 2-2. Report the calibration drift (the sum of the absolute mean and confidence interval) as a percentage of span. Use the example sheet shown in Figure 2-5.

7.2.7 Response Time. Using the charts from paragraph 6.3, calculate the time interval from concentration switching to 95 percent to the final stable value for all upscale and downscale tests. Report the mean of the three upscale test times and the mean of the three downscale test times. The two average times should not differ by more than 15 percent of the slower time. Report the slower time as the system response time. Use the example sheet shown in Figure 2-6.

7.2.8 Operational Test Period. During the 168-hour performance and operational test period, the continuous monitoring system shall not require any corrective maintenance, repair, replacement, or adjustment other than that clearly specified as required in the operation and maintenance manuals as routine and expected during a one-week period. If the continuous monitoring system operates within the specified performance parameters and does not require corrective maintenance, repair, replacement or adjustment other than as specified above during the 168-hour test period, the operational period will be successfully concluded. Failure of the continuous monitoring system to meet this requirement shall call for a repetition of the 168-hour test period. Portions of the test which were satisfactorily completed need not be repeated. Failure to meet any performance specifications shall call for a repetition of the one-week performance test period and that portion of the testing which is related to the failed specification. All maintenance and adjustments required shall be recorded. Output readings shall be recorded before and after all adjustments.

8. References.

8.1 "Monitoring Instrumentation for the Measurement of Sulfur Dioxide in Stationary Source Emissions," Environmental Protection Agency, Research Triangle Park, N.C., February 1973.

8.2 "Instrumentation for the Determination of Nitrogen Oxides Content of Stationary Source Emissions," Environmental Protection Agency, Research Triangle Park, N.C., Volume 1, APTD-0847, October 1971; Volume 2, APTD-0942, January 1972.

3.3 "Experimental Statistics," Department of Commerce, Handbook 91, 1963, pp. 3-31, paragraphs 3-3.1.4.

8.4 "Performance Specifications for Stationary-Source Monitoring Systems for Gases and Visible Emissions," Environmental Protection Agency, Research Triangle Park, N.C., EPA-650/2-74-013, January 1974.

Date _____ Reference Method Used ___

Mid-Range Calibration Gas Mixture

Sample 1 _____ ppm

Sample 2 _____ ppm

Sample 3 _____ ppm

Average _____ ppm

High-Range (span) Calibration Gas Mixture

Sample 1 _____ ppm

Sample 2 _____ ppm

Sample 3 _____ ppm

Average _____ ppm

Figure 2-1. Analysis of Calibration Gas Mixtures

Calibration Gas Mixture Data (From Figure 2-1)

Mid (50%) _____ppm High (90%) _____ppm

Run #	Calibration Gas Concentration, ppm	Measurement System Reading, ppm	Differences,[1] ppm
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			

	Mid	High
Mean difference	_____	_____
Confidence interval	+ _____	+ _____
Calibration error = $\frac{\text{Mean Difference}^{2} + \text{C.I.}}{\text{Average Calibration Gas Concentration}} \times 100$	_____ %	_____ %

[1] Calibration gas concentration - measurement system reading

[2] Absolute value

Figure 2-2. Calibration Error Determination

Test No.	Date and Time	Reference Method Samples: SO_2 Sample 1 (ppm)	NO_x Sample 1 (ppm)	NO_x Sample 2 (ppm)	NO_x Sample 3 (ppm)	NO_x Sample Average (ppm)	Analyzer 1-Hour Average (ppm)* SO_2	Analyzer 1-Hour Average (ppm)* NO_x	Difference (ppm) SO_2	Difference (ppm) NO_x
1										
2										
3										
4										
5										
6										
7										
8										
9										

Mean reference method test value (SO_2) _____ Mean reference method test value (NO_x) _____ Mean of the differences _____

95% Confidence intervals = ± _____ ppm (SO_2) = ± _____ ppm (NO_x)

Accuracies = $\frac{\text{Mean of the differences} + \text{95\% confidence interval}}{\text{Mean reference method value}} \times 100$ = _____ % (SO_2) = _____ % (NO_x)

* Explain and report method used to determine integrated averages

Figure 2-3. Accuracy Determination (SO_2 and NO_x) [57]

Data Set No.	Time Begin	Time End	Date	Zero Reading	Zero Drift (ΔZero)	Span Reading	Span Drift (ΔSpan)	Calibration Drift (Span- Zero)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								

Zero Drift = [Mean Zero Drift* _____ + CI (Zero) _____] ÷ [Span] x 100 = _____.
Calibration Drift = [Mean Span Drift* _____ + CI (Span) _____] ÷ [Span] x 100 = _____.
*Absolute Value.

Figure 2-4. Zero and Calibration Drift (2 hour)

Date and Time	Zero Reading	Zero Drift (ΔZero)	Span Reading (After zero adjustment)	Calibration Drift (ΔSpan)

Zero Drift = [Mean Zero Drift* _____ + C.I. (Zero) _____]
[Instrument Span] x 100 = _____.

Calibration Drift = [Mean Span Drift* _____ + C.I. (Span) _____]
÷ [Instrument Span] x 100 = _____.

* Absolute value

Figure 2-5. Zero and Calibration Drift (24-hour)

Date of Test _____

Span Gas Concentration _____ppm

Analyzer Span Setting _____ppm

Upscale	1 _____seconds	
	2 _____seconds	
	3 _____seconds	
	Average upscale response _____seconds	
Downscale	1 _____seconds	
	2 _____seconds	
	3 _____seconds	
	Average downscale response _____seconds	

System average response time (slower time) = _____seconds.

$$\%\text{deviation from slower system average response} = \left[\frac{\text{average upscale minus average downscale}}{\text{slower time}}\right] \times 100\% = ____.$$

Figure 2-6. Response Time

Performance Specification 3—Performance specifications and specification test procedures for monitors of CO_2 and O_2 from stationary sources.

1 Principle and Applicability.

1.1 Principle. Effluent gases are continuously sampled and are analyzed for carbon dioxide or oxygen by a continuous monitoring system. Tests of the system are performed during a minimum operating period to determine zero drift, calibration drift, and response time characteristics.

1 2 Applicability. This performance specification is applicable to evaluation of continuous monitoring systems for measurement of carbon dioxide or oxygen. These specifications contain test procedures, installation requirements, and data computation procedures for evaluating the acceptability of the continuous monitoring systems subject to approval by the Administrator. Sampling may include either extractive or non-extractive (in-situ) procedures.

2. Apparatus.

2 1 Continuous Monitoring System for Carbon Dioxide or Oxygen.

2 2 Calibration Gas Mixtures. Mixture of known concentrations of carbon dioxide or oxygen in nitrogen or air. Midrange and 90 percent of span carbon dioxide or oxygen concentrations are required The 90 percent of span gas mixture is to be used to set and check the analyzer span and is referred to as span gas For oxygen analyzers, if the span is higher than 21 percent O_2, ambient air may be used in place of the 90 percent of span calibration gas mixture. Triplicate analyses of the gas mixture (except ambient air) shall be performed within two weeks prior to use using Reference Method 3 of this part.

2 3 Zero Gas. A gas containing less than 100 ppm of carbon dioxide or oxygen.

2.4 Data Recorder. Analog chart recorder or other suitable device with input voltage range compatible with analyzer system output. The resolution of the recorder's data output shall be sufficient to allow completion of the test procedures within this specification.

3 Definitions.

3.1 Continuous Monitoring System. The total equipment required for the determination of carbon dioxide or oxygen in a given source effluent. The system consists of three major subsystems.

3.1.1 Sampling Interface That portion of the continuous monitoring system that performs one or more of the following operations: delineation, acquisition, transportation, and conditioning of a sample of the source effluent or protection of the analyzer from the hostile aspects of the sample or source environment

3 1 2 Analyzer That portion of the continuous monitoring system which senses the pollutant gas and generates a signal output that is a function of the pollutant concentration

3 1.3 Data Recorder. That portion of the continuous monitoring system that provides a permanent record of the output signal in terms of concentration units

3 2 Span. The value of oxygen or carbon dioxide concentration at which the continuous monitoring system is set that produces the maximum data display output. For the purposes of this method, the span shall be set no less than 1.5 to 2 5 times the normal carbon dioxide or normal oxygen concentration in the stack gas of the affected facility.

3 3 Midrange The value of oxygen or carbon dioxide concentration that is representative of the normal conditions in the stack gas of the affected facility at typical operating rates.

3.4 Zero Drift. The change in the continuous monitoring system output over a stated period of time of normal continuous operation when the carbon dioxide or oxygen concentration at the time for the measurements is zero.

3 5 Calibration Drift. The change in the continuous monitoring system output over a stated time period of normal continuous operation when the carbon dioxide or oxygen continuous monitoring system is measuring the concentration of span gas.

3 6 Operational Test Period. A minimum period of time over which the continuous monitoring system is expected to operate within certain performance specifications without unscheduled maintenance, repair, or adjustment.

3.7 Response time. The time interval from a step change in concentration at the input to the continuous monitoring system to the time at which 95 percent of the corresponding final value is displayed on the continuous monitoring system data recorder.

4. Installation Specification.

Oxygen or carbon dioxide continuous monitoring systems shall be installed at a location where measurements are directly representative of the total effluent from the affected facility or representative of the same effluent sampled by a SO_2 or NO_x continuous monitoring system. This requirement shall be complied with by use of applicable requirements in Performance Specification 2 of this appendix as follows:

4.1 Installation of Oxygen or Carbon Dioxide Continuous Monitoring Systems Not Used to Convert Pollutant Data. A sampling location shall be selected in accordance with the procedures under paragraphs 4.2.1 or 4.2.2, or Performance Specification 2 of this appendix.

4.2 Installation of Oxygen or Carbon Dioxide Continuous Monitoring Systems Used to Convert Pollutant Continuous Monitoring System Data to Units of Applicable Standards. The diluent continuous monitoring system (oxygen or carbon dioxide) shall be installed at a sampling location where measurements that can be made are representative of the effluent gases sampled by the pollutant continuous monitoring system(s). Conformance with this requirement may be accomplished in any of the following ways:

4 2.1 The sampling location for the diluent system shall be near the sampling location for the pollutant continuous monitoring system such that the same approximate point(s) (extractive systems) or path (in-situ systems) in the cross section is sampled or viewed.

4.2.2 The diluent and pollutant continuous monitoring systems may be installed at different locations if the effluent gases at both sampling locations are nonstratified as determined under paragraphs 4.1 or 4.3, Performance Specification 2 of this appendix and there is no in-leakage occurring between the two sampling locations. If the effluent gases are stratified at either location, the procedures under paragraph 4.2.2, Performance Specification 2 of this appendix shall be used for installing continuous monitoring systems at that location.

5. Continuous Monitoring System Performance Specifications.

The continuous monitoring system shall meet the performance specifications in Table 3-1 to be considered acceptable under this method.

6. Performance Specification Test Procedures.

The following test procedures shall be used to determine conformance with the requirements of paragraph 4. Due to the wide variation existing in analyzer designs and principles of operation, these procedures are not applicable to all analyzers. Where this occurs, alternative procedures, subject to the approval of the Administrator, may be employed. Any such alternative procedures must fulfill the same purposes (verify response, drift, and accuracy) as the following procedures, and must clearly demonstrate conformance with specifications in Table 3-1

6.1 Calibration Check. Establish a calibration curve for the continuous monitoring system using zero, midrange, and span concentration gas mixtures. Verify that the resultant curve of analyzer reading compared with the calibration gas value is consistent with the expected response curve as described by the analyzer manufacturer. If the expected response curve is not produced, additional calibration gas measurements shall be made, or additional steps undertaken to verify

the accuracy of the response curve of the analyzer.

6.2 Field Test for Zero Drift and Calibration Drift. Install and operate the continuous monitoring system in accordance with the manufacturer's written instructions and drawings as follows:

TABLE 3–1.—*Performance specifications*

Parameter	*Specification*
1. Zero drift (2 h) [1]	≤0.4 pct O_2 or CO_2.
2. Zero drift (24 h) [1]	≤0.5 pct O_2 or CO_2.
3. Calibration drift (2 h) [1]	≤0.4 pct O_2 or CO_2.
4. Calibration drift (24 h) [1]	≤0.5 pct O_2 or CO_2.
5. Operational period	168 h minimum.
6. Response time	10 min.

[1] Expressed as sum of absolute mean value plus 95 pct confidence interval of a series of tests.

6.2.1 Conditioning Period. Offset the zero setting at least 10 percent of span so that negative zero drift may be quantified. Operate the continuous monitoring system for an initial 168-hour conditioning period in a normal operational manner.

6.2.2. Operational Test Period. Operate the continuous monitoring system for an additional 168-hour period maintaining the zero offset. The system shall monitor the source effluent at all times except when being zeroed, calibrated, or backpurged.

6.2.3 Field Test for Zero Drift and Calibration Drift. Determine the values given by zero and midrange gas concentrations at two-hour intervals until 15 sets of data are obtained. For non-extractive continuous monitoring systems, determine the zero value given by a mechanically produced zero condition or by computing the zero value from upscale measurements using calibrated gas cells certified by the manufacturer. The midrange checks shall be performed by using certified calibration gas cells functionally equivalent to less than 50 percent of span. Record these readings on the example sheet shown in Figure 3–1. These two-hour periods need not be consecutive but may not overlap. In-situ CO_2 or O_2 analyzers which cannot be fitted with a calibration gas cell may be calibrated by alternative procedures acceptable to the Administrator. Zero and calibration corrections and adjustments are allowed only at 24-hour intervals or at such shorter intervals as the manufacturer's written instructions specify. Automatic corrections made by the continuous monitoring system without operator intervention or initiation are allowable at any time. During the entire 168-hour test period, record the values given by zero and span gas concentrations before and after adjustment at 24-hour intervals in the example sheet shown in Figure 3–2.

6.3 Field Test for Response Time.

6.3.1 Scope of Test.

This test shall be accomplished using the continuous monitoring system as installed, including sample transport lines if used. Flow rates, line diameters, pumping rates, pressures (do not allow the pressurized calibration gas to change the normal operating pressure in the sample line), etc., shall be at the nominal values for normal operation as specified in the manufacturer's written instructions. If the analyzer is used to sample more than one source (stack), this test shall be repeated for each sampling point.

6.3.2 Response Time Test Procedure.

Introduce zero gas into the continuous monitoring system sampling interface or as close to the sampling interface as possible. When the system output reading has stabilized, switch quickly to a known concentration of gas at 90 percent of span. Record the time from concentration switching to 95 percent of final stable response. After the system response has stabilized at the upper level, switch quickly to a zero gas. Record the time from concentration switching to 95 percent of final stable response. Alternatively, for nonextractive continuous monitoring systems, the highest available calibration gas concentration shall be switched into and out of the sample path and response times recorded. Perform this test sequence three (3) times. For each test, record the results on the data sheet shown in Figure 3–3.

7. Calculations, Data Analysis, and Reporting.

7.1 Procedure for determination of mean values and confidence intervals.

7.1.1 The mean value of a data set is calculated according to equation 3–1.

$$\bar{x}=\frac{1}{n}\sum_{i=1}^{n}x_i \qquad \text{Equation 3–1}$$

where:

x_i = absolute value of the measurements,
Σ = sum of the individual values,
$\bar{x}$ = mean value, and
n = number of data points.

7.2.1 The 95 percent confidence interval (two-sided) is calculated according to equation 3–2:

$$C.I._{95}=\frac{t_{.975}}{n\sqrt{n-1}}\sqrt{n(\Sigma x_i^2)-(\Sigma x_i)^2} \qquad \text{Equation 3–2}$$

where:

ΣX = sum of all data points,
$t_{.975}=t_{1-\alpha/2}$, and 23
C.I.$_{95}$ = 95 percent confidence interval estimates of the average mean value

Values for $t_{.975}$

n	$t_{.975}$
2	12.706
3	4.303
4	3.182
5	2.776
6	2.571
7	2.447
8	2.365
9	2.306
10	2.262
11	2.228
12	2.201
13	2.179
14	2.160
15	2.145
16	2.131

The values in this table are already corrected for n–1 degrees of freedom. Use n equal to the number of samples as data points.

7.2 Data Analysis and Reporting.

7.2.1 Zero Drift (2-hour). Using the zero concentration values measured each two hours during the field test, calculate the differences between the consecutive two-hour readings expressed in ppm. Calculate the mean difference and the confidence interval using equations 3–1 and 3–2. Record the sum of the absolute mean value and the confidence interval on the data sheet shown in Figure 3–1.

7.2.2 Zero Drift (24-hour). Using the zero concentration values measured every 24 hours during the field test, calculate the differences between the zero point after zero adjustment and the zero value 24 hours later just prior to zero adjustment. Calculate the mean value of these points and the confidence interval using equations 3–1 and 3–2. Record the zero drift (the sum of the absolute mean and confidence interval) on the data sheet shown in Figure 3–2.

7.2.3 Calibration Drift (2-hour). Using the calibration values obtained at two-hour intervals during the field test, calculate the differences between consecutive two-hour readings expressed as ppm. These values should be corrected for the corresponding zero drift during that two-hour period. Calculate the mean and confidence interval of these corrected difference values using equations 3–1 and 3–2. Do not use the differences between non-consecutive readings. Record the sum of the absolute mean and confidence interval upon the data sheet shown in Figure 3–1.

7.2.4 Calibration Drift (24-hour). Using the calibration values measured every 24 hours during the field test, calculate the differences between the calibration concentration reading after zero and calibration adjustment and the calibration concentration reading 24 hours later after zero adjustment but before calibration adjustment. Calculate the mean value of these differences and the confidence interval using equations 3–1 and 3–2. Record the sum of the absolute mean and confidence interval on the data sheet shown in Figure 3–2.

7.2.5 Operational Test Period. During the 168-hour performance and operational test period, the continuous monitoring system shall not receive any corrective maintenance, repair, replacement, or adjustment other than that clearly specified as required in the manufacturer's written operation and maintenance manuals as routine and expected during a one-week period. If the continuous monitoring system operates within the specified performance parameters and does not require corrective maintenance, repair, replacement or adjustment other than as specified above during the 168-hour test period, the operational period will be successfully concluded. Failure of the continuous monitoring system to meet this requirement shall call for a repetition of the 168 hour test period. Portions of the test which were satisfactorily completed need not be repeated. Failure to meet any performance specifications shall call for a repetition of the one-week performance test period and that portion of the testing which is related to the failed specification. All maintenance and adjustments required shall be recorded. Output readings shall be recorded before and after all adjustments.

7.2.6 Response Time. Using the data developed under paragraph 5.3, calculate the time interval from concentration switching to 95 percent to the final stable value for all upscale and downscale tests. Report the mean of the three upscale test times and the mean of the three downscale test times. The two average times should not differ by more than 15 percent of the slower time. Report the slower time as the system response time. Record the results on Figure 3–3.

8. References.

8.1 "Performance Specifications for Stationary Source Monitoring Systems for Gases and Visible Emissions," Environmental Protection Agency, Research Triangle Park, N.C., EPA–650/2–74–013, January 1974.

8.2 "Experimental Statistics," Department of Commerce, National Bureau of Standards Handbook 91, 1963, pp. 3–31, paragraphs 3–3.1.4.

(Secs. 111 and 114 of the Clean Air Act, as amended by sec. 4(a) of Pub. L. 91–604, 84 Stat. 1678 (42 U.S.C. 1857c–6, by sec. 15(c)(2) of Pub. L. 91–604, 85 Stat. 1713 (42 U.S.C. 1857g)).

Data Set No.	Time Begin	Time End	Date	Zero Reading	Zero Drift (ΔZero)	Span Reading	Span Drift (ΔSpan)	Calibration Drift (ΔSpan-ΔZero)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								

Zero Drift = [Mean Zero Drift* _____ + CI (Zero) _____] = _____.

Calibration Drift = [Mean Span Drift* _____ + CI (Span _____] = _____.

*Absolute Value.

Figure 3-1. Zero and Calibration Drift (2 Hour).

Date and Time	Zero Reading	Zero Drift (ΔZero)	Span Reading (After zero adjustment)	Calibration Drift (ΔSpan)

Zero Drift = [Mean Zero Drift* _____ + C.I. (Zero) _____]

= _____.

Calibration Drift = [Mean Span Drift* _____ + C.I. (Span) _____]

= _____.

* Absolute value

Figure 3-2. Zero and Calibration Drift (24-hour)

Date of Test _____

Span Gas Concentration _____ ppm

Analyzer Span Setting _____ ppm

Upscale
1. _____ seconds
2. _____ seconds
3. _____ seconds

Average upscale response _____ seconds

Downscale
1. _____ seconds
2. _____ seconds
3. _____ seconds

Average downscale response _____ seconds

System average response time (slower time) = _____ seconds

% deviation from slower system average response = $\frac{\text{average upscale minus average downscale}}{\text{slower time}} \times 100\%$

= _____.

Figure 3-3. Response

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). [68, 83]

APPENDIX C—DETERMINATION OF EMISSION RATE CHANGE

1. *Introduction.*

1.1 The following method shall be used to determine whether a physical or operational change to an existing facility resulted in an increase in the emission rate to the atmosphere. The method used is the Student's t test, commonly used to make inferences from small samples.

2. *Data.*

2.1 Each emission test shall consist of n runs (usually three) which produce n emission rates. Thus two sets of emission rates are generated, one before and one after the change, the two sets being of equal size.

2.2 When using manual emission tests, except as provided in § 60.8(b) of this part, the reference methods of Appendix A to this part shall be used in accordance with the procedures specified in the applicable subpart both before and after the change to obtain the data.

2.3 When using continuous monitors, the facility shall be operated as if a manual emission test were being performed. Valid data using the averaging time which would be required if a manual emission test were being conducted shall be used.

3. *Procedure.*

3.1 Subscripts a and b denote prechange and postchange respectively.

3.2 Calculate the arithmetic mean emission rate, $\bar{E}$, for each set of data using Equation 1.

$$\bar{E}=\frac{\sum_{i=1}^{n} E_i}{n}=\frac{E_1+E_2\ldots+E_n}{n} \qquad (1)$$

where:
E_i = Emission rate for the i th run.
n = number of runs

3.3 Calculate the sample variance, S^2, for each set of data using Equation 2.

$$S^2=\frac{\sum_{i=1}^{n}(E_i-\bar{E})^2}{n-1}=\frac{\sum_{i=1}^{n}E_i^2-\left(\sum_{i=1}^{n}E_i\right)^2\Big/n}{n-1} \qquad (2)$$

3.4 Calculate the pooled estimate, S_p, using Equation 3.

$$S_p=\left[\frac{(n_a-1)\ S_a^2+(n_b-1)\ S_b^2}{n_a+n_b-2}\right]^{1/2} \qquad (3)$$

3.5 Calculate the test statistic, t, using Equation 4.

$$t=\frac{\bar{E}_b-\bar{E}_a}{S_p\left[\frac{1}{n_a}+\frac{1}{n_b}\right]^{1/2}} \qquad (4)$$

4. *Results.*

4.1 If $\bar{E}_b>\bar{E}_a$ and $t>t'$, where t' is the critical value of t obtained from Table 1, then with 95% confidence the difference between $\bar{E}_b$ and $\bar{E}_a$ is significant, and an increase in emission rate to the atmosphere has occurred.

TABLE 1

Degree of freedom (n_a+n_b-2):	t' (95 percent confidence level)
2	2.920
3	2.353
4	2.132
5	2.015
6	1.943
7	1.895
8	1.860

For greater than 8 degrees of freedom, see any standard statistical handbook or text.

5.1 Assume the two performance tests produced the following set of data:

Test a:	Test b
Run 1. 100	115
Run 2. 95	120
Run 3. 110	125

5.2 *Using Equation 1—*

$$\bar{E}_a=\frac{100+95+110}{3}=102$$

$$\bar{E}_b=\frac{115+120+125}{3}=120$$

5.3 Using Equation 2—

$$S_a^2=\frac{(100-102)^2+(95-102)^2+(110-102)^2}{3-1}=58.5$$

$$S_b^2=\frac{(115-120)^2+(120-120)^2+(125-120)^2}{3-1}=25$$

5.4 Using Equation 3—

$$S_p=\left[\frac{(3-1)\ (58.5)+(3-1)\ (25)}{3+3-2}\right]^{1/2}=6.46$$

5.5 Using Equation 4—

$$t=\frac{120-102}{6.46\left[\frac{1}{3}+\frac{1}{3}\right]^{1/2}}=3.412$$

5.6 Since $(n_1+n_2-2)=4$, $t'=2.132$ (from Table 1). Thus since $t>t'$ the difference in the values of $\bar{E}_a$ and $\bar{E}_b$ is significant, and there has been an increase in emission rate to the atmosphere.

6. *Continuous Monitoring Data.*

6.1 Hourly averages from continuous monitoring devices, where available, should be used as data points and the above procedure followed.

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)). 68, 83

APPENDIX D—REQUIRED EMISSION INVENTORY INFORMATION

(a) Completed NEDS point source form(s) for the entire plant containing the designated facility, including information on the applicable criteria pollutants. If data concerning the plant are already in NEDS, only that information must be submitted which is necessary to update the existing NEDS record for that plant. Plant and point identification codes for NEDS records shall correspond to those previously assigned in NEDS; for plants not in NEDS, these codes shall be obtained from the appropriate Regional Office.

(b) Accompanying the basic NEDS information shall be the following information on each designated facility:

(1) The state and county identification codes, as well as the complete plant and point identification codes of the designated facility in NEDS. (The codes are needed to match these data with the NEDS data.)

(2) A description of the designated facility including, where appropriate:

(i) Process name.

(ii) Description and quantity of each product (maximum per hour and average per year).

(iii) Description and quantity of raw materials handled for each product (maximum per hour and average per year).

(iv) Types of fuels burned, quantities and characteristics (maximum and average quantities per hour, average per year).

(v) Description and quantity of solid wastes generated (per year) and method of disposal.

(3) A description of the air pollution control equipment in use or proposed to control the designated pollutant, including:

(i) Verbal description of equipment.

(ii) Optimum control efficiency, in percent. This shall be a combined efficiency when more than one device operate in series. The method of control efficiency determination shall be indicated (e.g., design efficiency, measured efficiency, estimated efficiency).

(iii) Annual average control efficiency, in percent, taking into account control equipment down time. This shall be a combined efficiency when more than one device operate in series.

(4) An estimate of the designated pollutant emissions from the designated facility (maximum per hour and average per year). The method of emission determination shall also be specified (e.g., stack test, material balance. emission factor).

(Sec. 114. Clean Air Act is amended (42 U.S C. 7414)). [68 83]

SECTION IV

FULL TEXT
OF
REVISIONS

IV. FULL TEXT OF REVISIONS

Ref.		Page
	36 FR 5931, 3/31/71 - List of Categories of Stationary Sources.	
	36 FR 15704, 8/17/71 - Proposed Standards for Five Categories: Fossil Fuel-Fired Steam Generators, Portland Cement Plants, Nitric Acid Plants, and Sulfuric Acid Plants.	
1.	36 FR 24876, 12/23/71 - Standards of Performance Promulgated for Fossil Fuel-Fired Steam Generators, Incinerators, Portland Cement Plants, Nitric Acid Plants, and Sulfuric Acid Plants.	1
1A.	37 FR 5767, 3/21/72 - Supplemental Statement in Connection with Final Promulgation.	21
2.	37 FR 14877, 7/26/72 - Standard for Sulfur Dioxide; Correction.	25
	37 FR 17214, 8/25/72 - Proposed Standards for Emissions During Startup, Shutdown, and Malfunction.	
3.	38 FR 13562, 5/23/73 - Amendment to Standards for Opacity and Corrections to Certain Test Methods.	26
	38 FR 15406, 6/11/73 - Proposed Standards of Performance for Asphalt Concrete Plants, Petroleum Refineries, Storage Vessels for Petroleum Liquids, Secondary Lead Smelters, Brass and Bronze Ingot Production Plants, Iron and Steel Plants, and Sewage Treatment Plants.	
4.	38 FR 28564, 10/15/73 - Standards of Performance Promulgated for Emissions During Startup, Shutdown, and Malfunction.	26
4A.	38 FR 10820, 5/2/73 - Proposed Standards of Performance for Emissions During Startup, Shutdown, & Malfunction.	28
5.	39 FR 9308, 3/8/74 - Standards of Performance Promulgated for Asphalt Concrete Plants, Petroleum Refineries, Storage Vessels for Petroleum Liquids, Secondary Lead Smelters, Brass and Bronze Ingot Production Plants, Iron and Steel Plants, and Sewage Treatment Plants; and Miscellaneous Amendments.	30

6. 39 FR 13776, 4/17/74 - Corrections to March 8, 1974 Federal Register. 45

7. 39 FR 15396, 5/3/74 - Corrections to March 8, 1974 and April 17, 1974 Federal Register. 46

8. 39 FR 20790, 6/14/74 - Standards of Performance, Miscellaneous Amendments. 46

39 FR 32852, 9/11/74 - Proposed Standards of Performance - Emission Monitoring Requirements and Performance Testing Methods.

39 FR 36102, 10/7/74 - Proposed Standards of Performance for State Plans for the Control of Existing Facilities.

39 FR 36946, 10/15/74 - Proposed Standards of Performance for Modification, Notification, and Reconstruction.

39 FR 37040, 10/16/74 - Proposed Standards of Performance for Primary Copper, Zinc, and Lead Smelters.

39 FR 37470, 10/21/74 - Proposed Standards of Performance for Ferroalloy Production Facilities.

39 FR 37466, 10/21/74 - Proposed Standards of Performance for Steel Plants: Electric Arc Furnaces.

39 FR 37602, 10/22/74 - Proposed Standards of Performance - Five Categories of Sources in the Phosphate Fertilizer Industry.

39 FR 37730, 10/23/74 - Proposed Standards of Performance for Primary Aluminum Reduction Plants.

39 FR 37922, 10/24/74 - Proposed Standards of Performance for Coal Preparation Plants.

9. 39 FR 37987, 10/25/74 - Region V Office: New Address. 51

10. 39 FR 39872, 11/12/74 - Opacity Provisions for New Stationary Sources Promulgated and Appendix A, Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources. 51

39 FR 39909, 11/12/74 - Response to Remand, Portland Cement Association v. Ruckelshaus, Reevaluation of Standards.

40 FR 831, 1/3/75 - Reevaluation of Opacity Standards of Performance for New Sources - Asphalt Concrete Plants.

11. 40 FR 2803, 1/16/75 - Amended Standard for Coal Refuse (promulgated December 23, 1971). 57

40 FR 17778, 4/22/75 - Standards of Performance, Proposed Opacity Provisions, Request for Public Comment.

12. 40 FR 18169, 4/25/75 - Delegation of Authority to State of Washington. 58

13. 40 FR 26677, 6/25/75 - Delegation of Authority to State of Idaho. 58

14. 40 FR 33152, 8/6/75 - Standards of Performance Promulgated for Five Categories of Sources in the Phosphate Fertilizer Industry. 59

40 FR 39927, 8/29/75 - Standards of Performance for Sulfuric Acid Plants - EPA Response to Remand.

40 FR 41834, 9/9/75 - Opacity Reevaluation - Asphalt Concrete, Response to Public Comments.

40 FR 42028, 9/10/75 - Proposed Opacity Standards for Fossil Fuel-Fired Steam Generators.

40 FR 42045, 9/10/75 - Standards of Performance for Fossil Fuel-Fired Steam Generators - EPA Response to Remand.

15. 40 FR 42194, 9/11/75 - Delegation of Authority to State of California. 74

16. 40 FR 43850, 9/23/75 - Standards of Performance Promulgated for Electric Arc Furnaces in the Steel Industry. 75

17. 40 FR 45170, 10/1/75 - Delegation of Authority to State of California. 80

18. 40 FR 46250, 10/6/75 - Standards of Performance Promulgated for Emission Monitoring Requirements and Revisions to Performance Testing Methods. 81

19. 40 FR 48347, 10/15/75 - Delegation of Authority to State of New York. 102

20. 40 FR 50718, 10/31/75 - Delegation of Authority to State of Colorado. 102

21. 40 FR 53340, 11/17/75 - Standards of Performance, Promulgation of State Plans for the control of Certain Pollutants from Existing Facilities (Subpart B and Appendix D). 103

40 FR 53420, 11/18/75 - Reevaluation of Opacity Standards for Secondary Brass and Bronze Plants and Secondary Lead Smelters.

22. 40 FR 58416, 12/16/75 - Standards of Performance, Promulgation of Modification, Notification and Reconstruction Provisions. 113

23. 40 FR 59204, 12/22/75 - Corrections to October 6, 1975, Federal Register. 118

24. 40 FR 59729, 12/30/75 - Delegation of Authority to State of Maine. 118

25. 41 FR 1913, 1/13/76 - Delegation of Authority to State of Michigan. 119

26. 41 FR 2231, 1/15/76 - Standards of Performance Promulgated for Coal Preparation Plants. 119

26. 41 FR 2332, 1/15/76 - Standards of Performance Promulgated for Primary Copper, Zinc and Lead Smelters. 123

27. 41 FR 3825, 1/26/76 - Standards of Performance Promulgated for Primary Aluminum Reduction Plants. 133

28. 41 FR 4263,1/29/76 - Delegation of Authority to Washington Local Authorities. 138

41 FR 7447, 2/18/76 - Reevaluation of Opacity Standards for Municipal Sewage Sludge Incinerators.

29. 41 FR 7749, 2/20/76 - Delegation of Authority to State of Oregon. 138

30. 41 FR 8346, 2/26/76 - Correction to the Primary Copper, Zinc, and Lead Smelter Standards Promulgated on 1/15/76. 139

31. 41 FR 11820, 3/22/76 - Delegation of Authority to State of Connecticut. 139

32. 41 FR 17549, 4/27/76 - Delegation of Authority to State of South Dakota. 139

33. 41 FR 18498, 5/4/76 - Standards of Performance Promulgated for Ferroalloy Production Facilities. 140

41 FR 19374, 5/12/76 - Revised Public Comment Summary for Modification, Notification, and Reconstruction.

41 FR 19584, 5/12/76 - Phosphate Fertilizer Plants, Draft Guidelines Document - Notice of Availability.

34. 41 FR 19633, 5/13/76 - Delegation of Authority to Commonwealth of Massachusetts and Delegation of Authority to State of New Hampshire. 145

35. 41 FR 20659, 5/20/76 - Correction to Ferroalloy Production Facilities Standards Promulgated on May 4, 1976. 146

36. 41 FR 21450, 5/26/76 - Delegation of Authority to State of California. 146

41 FR 23059, 6/8/76 - Proposed Amendments to Reference Methods 1-8.

37. 41 FR 24124, 6/15/76 - Delegation of Authority to State of Utah. 146

38. 41 FR 24885, 6/21/76 - Delegation of Authority to State of Georgia. 147

39. 41 FR 27967, 7/8/76 - Delegation of Authority to State of California. 147

40. 41 FR 33264, 8/9/76 - Delegation of Authority to State of California. 148

41. 41 FR 34628, 8/16/76 - Delegation of Authority to Virgin Islands. 148

42. 41 FR 35185, 8/20/76 - Revision to Emission Monitoring Requirements. 149

41 FR 36600, 8/30/76 - Proposed Revisions to Standards of Performance for Petroleum Refinery Fluid Catalytic Cracking Unit Catalyst Regenerators.

43. 41 FR 36918, 9/1/76 - Standards of Performance - Availability of Information. 149

44. 41 FR 40107, 9/17/76 - Delegation of Authority to State of California. 149

45. 41 FR 40467, 9/20/76 - Delegation of Authority to State of Alabama. 150

41 FR 42012, 9/24/76 - Proposed Standards of Performance for Kraft Pulp Mills.

46. 41 FR 43148, 9/30/76 - Delegation of Authority to the State State of Indiana. 150

41 FR 43866, 10/4/76 - Proposed Revisions to Standards of Performance for Petroleum Refinery Sulfur Recovery Plants.

47. 41 FR 44859, 10/13/76 - Delegation of Authority to State of North Dakota. 150

41 FR 46618, 10/22/76 - Advanced Notice of Proposed Rulemaking of Air Emission Regulations - Synthetic Organic Chemical Manufacturing Industry.

41 FR 47495, 10/29/76 - Proposed Standards of Performance for Kraft Pulp Mills; Correction.

48. 41 FR 48342, 11/3/76 - Delegation of Authority to State of California. 151

41 FR 48706, 11/4/76 - Proposed Revisions to Emission Guidelines for the Control of Sulfuric Acid Mist from Existing Sulfuric Acid Production Units.

49. 41 FR 51397, 11/22/76 - Amendments to Subpart D Promulgated. 151

41 FR 51621, 11/23/76 - Proposed Standards of Performance for Kraft Pulp Mills - Extension of Comment Period.

41 FR 52079, 11/26/76 - Proposed Revision to Emission Guidelines for the Control of Sulfuric Acid Mist from Existing Sulfuric Acid Production Units; Correction.

50. 41 FR 52299, 11/29/76 - Amendments to Reference Methods 13A and 13B Promulgated. 154

51. 41 FR 53017, 12/3/76 - Delegation of Authority to Pima County Health Department; Arizona. 155

52. 41 FR 54757, 12/15/76 - Delegation of Authority to State of California. 155

53. 41 FR 55531, 12/21/76 - Delegation of Authority to the State of Ohio. 156

41 FR 55792, 12/22/76 - Proposed Revisions to Standards of Performance for Lignite-Fired Steam Generators.

54. 41 FR 56805, 12/30/76 - Delegation of Authority to the States of North Carolina, Nebraska, and Iowa. 156

55. 42 FR 1214, 1/6/77 - Delegation of Authority to State of Vermont. 157

42 FR 2841, 1/13/77 - Proposed Standards of Performance for Grain Elevators.

56. 42 FR 4124, 1/24/77 - Delegation of Authority to the State of South Carolina. 158

42 FR 4863, 1/26/77 - Proposed Revisions to Standards of Performance for Sewage Sludge Incinerators.

42 FR 4883, 1/26/77 - Receipt of Application and Approval of Alternative Test Method. 158

42 FR 5121, 1/27/77 - Notice of Study to Review Standards for Fossil Fuel-Fired Steam Generators; SO_2 Emissions.

57. 42 FR 5936, 1/31/77 - Revisions to Emission Monitoring Requirements and to Reference Methods Promulgated. 159

58. 42 FR 6812, 2/4/77 - Delegation of Authority to City of Philadelphia. 161

42 FR 10019, 2/18/77 - Proposed Standards for Sewage Treatment Plants; Correction.

42 FR 12130, 3/2/77 - Proposed Revision to Standards of Performance for Iron & Steel Plants; Basic Oxygen Process Furnaces.

42 FR 13566, 3/11/77 - Proposed Standards of Performance for Grain Elevators; Extension of Comment Period.

59. 42 FR 16777, 3/30/77 - Correction of Region V Address and Delegation of Authority to the State of Wisconsin. 161

42 FR 18884, 4/11/77 - Notice of Public Hearing on Coal-Fired Steam Generators SO_2 Emissions.

42 FR 22506, 5/3/77 - Proposed Standards of Performance for Lime Manufacturing Plants.

60. 42 FR 26205, 5/23/77 - Revision of Compliance with Standards and Maintenance Requirements. 162

42 FR 26222, 5/23/77 - Proposed Revision of Reference Method 11.

42 FR 32264, 6/24/77 - Suspension of Proposed Standards of Performance for Grain Elevators.

61. 42 FR 32426, 6/24/77 - Revisions to Standards of Performance for Petroleum Refinery Fluid Catalytic Cracking Unit Catalyst Regenerators Promulgated. 162

62. 42 FR 37000, 7/19/77 - Revision and Reorganization of the Units and Abbreviations. 164

42 FR 37213, 7/20/77 - Notice of Intent to Develop Standards of Performance for Glass Melting Furnaces.

63. 42 FR 37386, 7/21/77 - Delegation of Authority to the State of New Jersey. 165

64. 42 FR 37936, 7/25/77 - Applicability Dates Incorporated into Existing Regulations. 165

65. 42 FR 38178, 7/27/77 - Standards of Performance for Petroleum Refinery Fluid Catalytic Cracking Unit Catalyst Regenerators and Units and Measures; Corrections. 168

66. 42 FR 39389, 8/4/77 - Standards of Performance for Petroleum Refinery Fluid Catalytic Cracking Unit Catalyst Regenerators, Correction. 168

67. 42 FR 41122, 8/15/77 - Amendments to Subpart D; Correction. 168

68. 42 FR 41424, 8/17/77 - Authority Citations; Revision 169

69. 42 FR 41754, 8/18/77 - Revision to Reference Methods 1-8 Promulgated. 170

70. 42 FR 44544, 9/6/77 - Delegation of Authority to the State of Montana. 206

71. 42 FR 44812, 9/7/77 - Standards of Performance, Applicability Dates; Correction. 206

42 FR 45705, 9/12/77 - Notice of Delegation of Authority to the State of Indiana.

72. 42 FR 46304, 9/15/77 - Delegation of Authority to the State of Wyoming. 207

42 FR 53782, 10/3/77 - Proposed Standards of Performance for Stationary Gas Turbines.

73. 42 FR 55796, 10/18/77 - Emission Guidelines for Sulfuric Acid Mist Promulgated. 208

74. 42 FR 57125, 11/1/77 - Amendments to General Provisions and Copper Smelter Standards Promulgated. 209

75. 42 FR 58520, 11/10/77 - Amendment to Sewage Sludge Incinerators Promulgated. 211

76. 42 FR 61537, 12/5/77 - Opacity Provisions for Fossil-Fuel-Fired Steam Generators Promulgated. 212

42 FR 61541, 12/5/77 - Opacity Standards for Fossil-Fuel-Fired Steam Generators: Final EPA Response to Remand.

77. 42 FR 62137, 12/9/77 - Delegation of Authority to the Commonwealth of Puerto Rico. 214

42 FR 62164, 12/9/77 - Proposed Standards for Stationary Gas Turbines; Extension of Comment Period.

78. 43 FR 9, 1/3/78 - Delegation of Authority to the State of Minnesota. 214

79. 43 FR 1494, 1/10/78 - Revision of Reference Method II Promulgated. 215

80. 43 FR 3360, 1/25/78 - Delegation of Authority to the Commonwealth of Kentucky. 219

81. 43 FR 6770, 2/16/78 - Delegation of Authority to the State of Delaware. 220

82. 43 FR 7568, 2/23/78 - Standards of Performance Promulgated for Kraft Pulp Mills. 221

83. 43 FR 8800, 3/3/78 - Revision of Authority Citations. 249

84. 43 FR 9276, 3/7/78 - Standards of Performance Promulgated for Lignite-Fired Steam Generators. 250

85. 43 FR 9452, 3/7/78 - Standards of Performance Promulgated for Lime Manufacturing Plants. 253

86. 43 FR 10866, 3/15/78 - Standards of Performance Promulgated for Petroleum Refinery Claus Sulfur Recovery Plants. 255

87. 43 FR 11984, 3/23/78 - Corrections and Amendments to Reference Methods 1-8. 262

43 FR 14602, 4/6/78 - Notice of Regulatory Agenda.

88. 43 FR 15600, 4/13/78 - Standards of Performance Promulgated for Basic Oxygen Process Furnaces: Opacity Standard. 265

89. 43 FR 20986, 5/16/78 - Delegation of Authority to State/Local Air Pollution Control Agencies in Arizona, California, and Nevada. 268

43 FR 21616, 5/18/78 - Proposed Standards of Performance for Storage Vessels for Petroleum Liquids.

43 FR 22221, 5/24/78 - Correction to Proposed Standards of Performance for Storage Vessels for Petroleum Liquids.

90. 43 FR 34340, 8/3/78 - Standards of Performance Promulgated for Grain Elevators. 269

43 FR 34349, 8/3/78 - Reinstatement of Proposed Standards for Grain Elevators.

91. 43 FR 34784, 8/7/78 - Amendments to Standards of Performance for Kraft Pulp Mills and Reference Method 16. 277

43 FR 34892, 8/7/78 - Proposed Regulatory Revisions Air Quality Surveillance and Data Reporting.

43 FR 38872, 8/31/78 - Proposed Priority List for Standards of Performance for New Stationary Sources.

43 FR 42154, 9/19/78 - Proposed Standards of Performance for Electric Utility Steam Generating Units and Announcement of Public Hearing on Proposed Standards.

43 FR 42186, 9/19/78 - Proposed Standards of Performance for Primary Aluminum Industry.

92. 43 FR 47692, 10/16/78 - Delegation of Authority to the State of Rhode Island. 278

43 FR 54959, 11/24/78 - Public Hearing on Proposed Standards for Electric Utility Steam Generating Units.

43 FR 55258, 11/27/78 - Electric Utility Steam Generating Units; Correction and Additional Information.

43 FR 57834, 12/8/78 - Electric Utility Steam Generating Units; Additional Information.

93. 44 FR 2578, 1/12/79 - Amendments to Appendix A - Reference Method 16. 279

94. 44 FR 3491, 1/17/79 - Wood Residue-Fired Steam Generators; Applicability Determination. 280

95. 44 FR 7714, 2/7/79 - Delegation of Authority to State of Texas. 282

96. 44 FR 13480, 3/12/79 - Petroleum Refineries - Clarifying Amendment. 282

44 FR 15742, 3/15/79 - Review of Performance Standards for Sulfuric Acid Plants.

44 FR 17120, 3/20/79 - Proposed Amendment to Petroleum Refinery Claus Sulfur Recovery Plants.

44 FR 17460, 3/21/79 - Review of Standards for Iron & Steel Plants Basic Oxygen Furnaces.

44 FR 21754, 4/11/79 - Primary Aluminum Plants; Draft Guideline Document; Availability.

97. 44 FR 23221, 4/19/79 - Delegation of Authority to Washington Local Agency 284

44 FR 29828, 5/22/79 - Kraft Pulp Mills; Final Guideline Document; Availability.

44 FR 31596, 5/31/79 - Definition of "Commenced" for Standards of Performance for New Stationary Sources.

98. 44 FR 33580, 6/11/79 - Standards of Performance Promulgated for Electric Utility Steam Generating Units. 285

44 FR 34193, 6/14/79 - Air Pollution Prevention and Control; Addition to the List of Categories of Stationary Sources.

44 FR 34840, 6/15/79 - Proposed Standards of Performance for New Stationary Sources; Glass Manufacturing Plants.

44 FR 35265, 6/19/79 - Review of Performance Standards: Nitric Acid Plants.

44 FR 35953, 6/19/79 - Review of Performance Standards: Secondary Brass and Bronze Ingot Production.

44 FR 37632, 6/28/79 - Fossil-Fuel-Fired Industrial Steam Generators; Advanced Notice of Proposed Rulemaking.

44 FR 37960, 6/29/79 - Proposed Adjustment of Opacity Standard for Fossil-Fuel-Fired Steam Generators.

44 FR 43152, 7/23/79 - Proposed Standards of Performance for Stationary Internal Combustion Engines.

44 FR 47778, 8/15/79 - Proposed Standards for Glass Manufacturing Plants; Extension of Comment Period.

99. 44 FR 49222, 8/21/79 - Priority List and Additions to the List of Categories of Stationary Sources Promulgated. 331

44 FR 49298, 8/22/79 - Kraft Pulp Mills; Final Guideline Document; Correction.

100. 44 FR 51225, 8/31/79 - Standards of Performance for Asphalt Concrete Plants; Review of Standards. 335

44 FR 52324, 9/7/79 - New Source Performance Standards for Sulfuric Acid Plants; Final EPA Remand Response.

101. 44 FR 52792, 9/10/79 - Standards of Performance for New Stationary Sources; Gas Turbines 338

44 FR 54072, 9/18/79 - Standards of Performance for Stationary Internal Combustion Engines; Extension of Comment Period.

44 FR 54970, 9/21/79 - Proposed Standards of Performance for Phosphate Rock Plants.

102. 44 FR 55173, 9/25/79 - Standards of Performance for New Stationary Sources; General Provisions; Definitions. 354

44 FR 57792, 10/5/79 - Proposed Standards of Performance for Automobile and Light-Duty Truck Surface Coating Operations.

44 FR 58602, 10/10/79 - Proposed Standards for Continuous Monitoring Performance Specifications.

44 FR 60759, 10/22/79 - Review of Standards of Performance for Petroleum Refineries.

44 FR 60761, 10/22/79 - Review of Standards of Performance for Portland Cement Plants.

103. 44 FR 61542, 10/25/79 - Amendment to Standards of Performance for Petroleum Refinery Claus Sulfur Recovery Plants. 356

44 FR 62914, 11/1/79 - Proposed Standards of Performance for Phosphate Rock Plants; Extension of Comment Period.

104. 44 FR 65069, 11/9/79 - Amendment to Regulations for Ambient Air Quality Monitoring and Data Reporting. 358

44 FR 67934, 11/27/79 - Review of Standards of Performance for Sewage Treatment Plants.

44 FR 67938, 11/27/79 - Review of Standards of Performance for Incinerators.

105. 44 FR 69298, 12/3/79 - Delegation of Authority to the State of Maryland. 358

106. 44 FR 70465, 12/7/79 - Delegation of Authority to the State of Delaware. 359

44 FR 57408, 12/20/79 - Standards of Performance for Continuous Monitoring Performance Specifications; Extension of Comment Period.

107. 44 FR 76786, 12/28/79 - Amendments to Standards of Performance for Fossil-Fuel-Fired Steam Generators. 360

45 FR 2790, 1/14/80 - Proposed Standards of Performance for Lead-Acid Battery Manufacture.

108. 45 FR 3034, 1/16/80 - Delegation of Authority to Commonwealth of Pennsylvania. 360

45 FR 3333, 1/17/80 - Proposed Standards of Performance for Phosphate Rock Plants; Extension of Comment Period.

109. 45 FR 5616, 1/23/80 - Modification, Notification, and Reconstruction; Amendment and Correction. 361

45 FR 7758, 2/4/80 - Proposed Standards of Performance for Ammonium Sulfate Manufacture.

110. 45 FR 8211, 2/6/80 - Standards of Performance for Electric Utility Steam Generating Units; Decision in Response to Petitions for Reconsideration. 363

45 FR 11444, 2/20/80 - Proposed Standards of Performance for Continuous Monitoring Specifications.

45 FR 13991, 3/3/80 - Proposed Clarifying Amendment for Standards of Performance for Petroleum Refineries.

45 FR 20155, 3/27/80 - Notice of Determination of Applicability of New Source Performance Standards (NSPS) to Potomac Electric Power Co. (PEDCo) Chalk Point Unit 4.

45 FR 21302, 4/1/80 - Proposed Adjustment of Opacity Standard for Fossil-Fuel-Fired Steam Generator.

111. 45 FR 23374, 4/4/80 - Standards of Performance for Petroleum Liquid Storage Vessels. 386

45 FR 26294, 4/17/80 - Primary Aluminum Plants; Notice of Availability of Final Guideline Document.

45 FR 26304, 4/17/80 - Review of Standards of Performance for Secondary Lead Smelters.

45 FR 26910, 4/21/80 - Review of Standards of Performance for Electric Arc Furnaces (Steel Industry).

112. 45 FR 36077, 5/29/80 - Adjustment of Opacity Standard for Fossil Fuel Fired Steam Generator. 394

45 FR 39766, 6/11/80 - Proposed Standards of Performance for Organic Solvent Cleaners.

113. 45 FR 41852, 6/20/80 - Revised Reference Methods 13A and 13B. 395

114. 45 FR 44202, 6/30/80 - Amendments to Standards of Performance for Primary Aluminum Industry. 401

Title 40—PROTECTION OF ENVIRONMENT

Chapter I—Environmental Protection Agency

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

On August 17, 1971 (36 F.R. 15704) pursuant to section 111 of the Clean Air Act as amended, the Administrator proposed standards of performance for steam generators, portland cement plants, incinerators, nitric acid plants, and sulfuric acid plants. The proposed standards, applicable to sources the construction or modification of which was initiated after August 17, 1971, included emission limits for one or more of four pollutants (particulate matter, sulfur dioxide, nitrogen oxides, and sulfuric acid mist) for each source category. The proposal included requirements for performance testing, stack gas monitoring, record keeping and reporting, and procedures by which EPA will provide preconstruction review and determine the applicability of the standards to specific sources.

Interested parties were afforded an opportunity to participate in the rule making by submitting comments. A total of more than 200 interested parties, including Federal, State, and local agencies, citizens groups, and commercial and industrial organizations submitted comments. Following a review of the proposed regulations and consideration of the comments, the regulations, including the appendix, have been revised and are being promulgated today. The principal revisions are described below:

1. Particulate matter performance testing procedures have been revised to eliminate the requirement for impingers in the sampling train. Compliance will be based only on material collected in the dry filter and the probe preceding the filter. Emission limits have been adjusted as appropriate to reflect the change in test methods. The adjusted standards require the same degree of particulate control as the originally proposed standards.

2. Provisions have been added whereby alternative test methods can be used to determine compliance. Any person who proposes the use of an alternative method will be obliged to provide evidence that the alternative method is equivalent to the reference method.

3. The definition of modification, as it pertains to increases in production rate and changes of fuels, has been clarified. Increases in production rates up to design capacity will not be considered a modification nor will fuel switches if the equipment was originally designed to accommodate such fuels. These provisions will eliminate inequities where equipment had been put into partial operation prior to the proposal of the standards.

4. The definition of a new source was clarified to include construction which is completed within an organization as well as the more common situations where the facility is designed and constructed by a contractor.

5. The provisions regarding requests for EPA plan review and determination of construction or modification have been modified to emphasize that the submittal of such requests and attendant information is purely voluntary. Submittal of such a request will not bind the operator to supply further information; however, lack of sufficient information may prevent the Administrator from rendering an opinion. Further provisions have been added to the effect that information submitted voluntarily for such plan review or determination of applicability will be considered confidential, if the owner or operator requests such confidentiality.

6. Requirements for notifying the Administrator prior to commencing construction have been deleted. As proposed, the provision would have required notification prior to the signing of a contract for construction of a new source. Owners and operators still will be required to notify the Administrator 30 days prior to initial operation and to confirm the action within 15 days after startup.

7. Revisions were incoporated to permit compliance testing to be deferred up to 60 days after achieving the maximum production rate but no longer than 180 days after initial startup. The proposed regulation could have required testing within 60 days after startup but defined startup as the beginning of routine operation. Owners or operators will be required to notify the Administrator at least 10 days prior to compliance testing so that an EPA observer can be on hand. Procedures have been modified so that the equipment will have to be operated at maximum expected production rate, rather than rated capacity, during compliance tests.

8. The criteria for evaluating performance testing results have been simplified to eliminate the requirement that all values be within 35 percent of the average. Compliance will be based on the average of three repetitions conducted in the specified manner.

9. Provisions were added to require owners or operators of affected facilities to maintain records of compliance tests, monitoring equipment, pertinent analyses, feed rates, production rates, etc. for 2 years and to make such information available on request to the Administrator. Owners or operators will be required to summarize the recorded data daily and to convert recorded data into the applicable units of the standard.

10. Modifications were made to the visible emission standards for steam generators, cement plants, nitric acid plants, and sulfuric acid plants. The Ringelmann standards have been deleted; all limits will be based on opacity. In every case, the equivalent opacity will be at least as stringent as the proposed Ringelmann number. In addition, requirements have been altered for three of the source categories so that allowable emissions will be less than 10 percent opacity rather than 5 percent or less opacity. There were many comments that observers could not accurately evaluate emissions of 5 percent opacity. In addition, drafting errors in the proposed visible emission limits for cement kilns and steam generators were corrected. Steam generators will be limited to visible emissions not greater than 20 percent opacity and cement kilns to not greater than 10 percent opacity.

11. Specifications for monitoring devices were clarified, and directives for calibration were included. The instruments are to be calibrated at least once a day, or more often if specified by the manufacturer. Additional guidance on the selection and use of such instruments will be provided at a later date.

12. The requirement for sulfur dioxide monitoring at steam generators was deleted for those sources which will achieve the standard by burning low-sulfur fuel, provided that fuel analysis is conducted and recorded daily. American Society for Testing and Materials sampling techniques are specified for coal and fuel oil.

13. Provisions were added to the steam generator standards to cover those instances where mixed fuels are burned. Allowable emissions will be determined by prorating the heat input of each fuel, however, in the case of sulfur dioxide, the provisions allow operators the option of burning low-sulfur fuels (probably natural gas) as a means of compliance.

14. Steam generators fired with lignite have been exempted from the nitrogen oxides limit. The revision was made in view of the lack of information on some types of lignite burning. When more information is developed, nitrogen oxides standards may be extended to lignite fired steam generators.

15. A provision was added to make it explicit that the sulfuric acid plant standards will not apply to scavenger acid plants. As stated in the background document, APTD 0711, which was issued at the time the proposed standards were published, the standards were not meant to apply to such operations, e.g., where sulfuric acid plants are used primarily to control sulfur dioxide or other sulfur compounds which would otherwise be vented into the atmosphere.

16. The regulation has been revised to provide that all materials submitted pursuant to these regulations will be directed to EPA's Office of General Enforcement.

17. Several other technical changes have also been made. States and interested parties are urged to make a careful reading of these regulations.

As required by section 111 of the Act, the standards of performance promulgated herein "reflect the degree of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated". The standards of performance are based on stationary source testing conducted by the Environmental Protection Agency and/or contractors and on data derived from various other sources, including the available technical literature. In the comments on the proposed standards, many questions were raised as to costs and

demonstrated capability of control systems to meet the standards. These comments have been evaluated and investigated, and it is the Administrator's judgment that emission control systems capable of meeting the standards have been adequately demonstrated and that the standards promulgated herein are achievable at reasonable costs.

The regulations establishing standards of performance for steam generators, incinerators, cement plants, nitric acid plants, and sulfuric acid plants are hereby promulgated effective on publication and apply to sources, the construction or modification of which was commenced after August 17, 1971.

Dated: December 16, 1971.

WILLIAM D. RUCKELSHAUS,
Administrator,
Environmental Protection Agency.

A new Part 60 is added to Chapter I, Title 40, Code of Federal Regulations, as follows:

Subpart A—General Provisions

Sec.
60.1 Applicability.
60.2 Definitions.
60.3 Abbreviations.
60.4 Address.
60.5 Determination of construction or modification.
60.6 Review of plans.
60.7 Notification and recordkeeping.
60.8 Performance tests.
60.9 Availability of information.
60.10 State authority.

Subpart D—Standards of Performance for Fossil Fuel-Fired Steam Generators

60.40 Applicability and designation of affected facility.
60.41 Definitions.
60.42 Standard for particulate matter.
60.43 Standard for sulfur dioxide.
60.44 Standard for nitrogen oxides.
60.45 Emission and fuel monitoring.
60.46 Test methods and procedures.

Subpart E—Standards of Performance for Incinerators

60.50 Applicability and designation of affected facility.
60.51 Definitions.
60.52 Standard for particulate matter.
60.53 Monitoring of operations.
60.54 Test methods and procedures.

Subpart F—Standards of Performance for Portland Cement Plants

60.60 Applicability and designation of affected facility.
60.61 Definitions.
60.62 Standard for particulate matter.
60.63 Monitoring of operations.
60.64 Test methods and procedures.

Subpart G—Standards of Performance for Nitric Acid Plants

60.70 Applicability and designation of affected facility.
60.71 Definitions.
60.72 Standard for nitrogen oxides.
60.73 Emission monitoring.
60.74 Test methods and procedures.

Subpart H—Standards of Performance for Sulfuric Acid Plants

60.80 Applicability and designation of affected facility.
60.81 Definitions.
60.82 Standard for sulfur dioxide.
60.83 Standard for acid mist.
60.84 Emission monitoring.
60.85 Test methods and procedures.

APPENDIX—TEST METHODS

Method 1—Sample and velocity traverses for stationary sources.
Method 2—Determination of stack gas velocity and volumetric flow rate (Type S pitot tube).
Method 3—Gas analysis for carbon dioxide, excess air, and dry molecular weight.
Method 4—Determination of moisture in stack gases.
Method 5—Determination of particulate emissions from stationary sources.
Method 6—Determination of sulfur dioxide emissions from stationary sources.
Method 7—Determination of nitrogen oxide emissions from stationary sources.
Method 8—Determination of sulfuric acid mist and sulfur dioxide emissions from stationary sources.
Method 9—Visual determination of the opacity of emissions from stationary sources.

AUTHORITY: The provisions of this Part 60 issued under sections 111, 114, Clean Air Act; Public Law 91-604, 84 Stat. 1713.

Subpart A—General Provisions

§ 60.1 Applicability.

The provisions of this part apply to the owner or operator of any stationary source, which contains an affected facility the construction or modification of which is commenced after the date of publication in this part of any proposed standard applicable to such facility.

§ 60.2 Definitions.

As used in this part, all terms not defined herein shall have the meaning given them in the Act:

(a) "Act" means the Clean Air Act (42 U.S.C. 1857 et seq., as amended by Public Law 91-604, 84 Stat. 1676).

(b) "Administrator" means the Administrator of the Environmental Protection Agency or his authorized representative.

(c) "Standard" means a standard of performance proposed or promulgated under this part.

(d) "Stationary source" means any building, structure, facility, or installation which emits or may emit any air pollutant.

(e) "Affected facility" means, with reference to a stationary source, any apparatus to which a standard is applicable.

(f) "Owner or operator" means any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part.

(g) "Construction" means fabrication, erection, or installation of an affected facility.

(h) "Modification" means any physical change in, or change in the method of operation of, an affected facility which increases the amount of any air pollutant (to which a standard applies) emitted by such facility or which results in the emission of any air pollutant (to which a standard applies) not previously emitted, except that:

(1) Routine maintenance, repair, and replacement shall not be considered physical changes, and

(2) The following shall not be considered a change in the method of operation:

(i) An increase in the production rate, if such increase does not exceed the operating design capacity of the affected facility;

(ii) An increase in hours of operation;

(iii) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to such facility, as provided by § 60.1, the affected facility is designed to accommodate such alternative use.

(i) "Commenced" means that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a binding agreement or contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

(j) "Opacity" means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

(k) "Nitrogen oxides" means all oxides of nitrogen except nitrous oxide, as measured by test methods set forth in this part.

(l) "Standard of normal conditions" means 70° Fahrenheit (21.1° centigrade) and 29.92 in. Hg (760 mm. Hg).

(m) "Proportional sampling" means sampling at a rate that produces a constant ratio of sampling rate to stack gas flow rate.

(n) "Isokinetic sampling" means sampling in which the linear velocity of the gas entering the sampling nozzle is equal to that of the undisturbed gas stream at the sample point.

(o) "Startup" means the setting in operation of an affected facility for any purpose.

§ 60.3 Abbreviations.

The abbreviations used in this part have the following meanings in both capital and lower case:

B.t.u.—British thermal unit.
cal.—calorie(s).
c.f.m.—cubic feet per minute.
CO_2—carbon dioxide.
g.—gram(s).
gr.—grain(s).
mg.—milligram(s).
mm.—millimeter(s).
l.—liter(s).
nm.—nanometer(s), -10^{-9} meter.
μg.—microgram(s), 10^{-6} gram.
Hg.—mercury.
in.—inch(es).
K—1,000.
lb.—pound(s).
ml.—milliliter(s).
No.—number.
%—percent.
NO—nitric oxide.
NO_2—nitrogen dioxide.
NO_x—nitrogen oxides.
$NM.^3$—normal cubic meter.
s.c.f.—standard cubic feet.
SO_2—sulfur dioxide.
H_2SO_4—sulfuric acid.
SO_3—sulfur trioxide.

ft.³—cubic feet.
ft.²—square feet.
min.—minute(s).
hr.—hour(s).

§ 60.4 Address.

All applications, requests, submissions, and reports under this part shall be submitted in triplicate and addressed to the Environmental Protection Agency, Office of General Enforcement, Waterside Mall SW., Washington, DC 20460.

§ 60.5 Determination of construction or modification.

When requested to do so by an owner or operator, the Administrator will make a determination of whether actions taken or intended to be taken by such owner or operator constitute construction or modification or the commencement thereof within the meaning of this part.

§ 60.6 Review of plans.

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.

(b) (1) A separate request shall be submitted for each affected facility.

(2) Each request shall (i) identify the location of such affected facility, and (ii) be accompanied by technical information describing the proposed nature, size, design, and method of operation of such facility, including information on any equipment to be used for measurement or control of emissions.

(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall (1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or (2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

§ 60.7 Notification and record keeping.

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification as follows:

(1) A notification of the anticipated date of initial startup of an affected facility not more than 60 days or less than 30 days prior to such date.

(2) A notification of the actual date of initial startup of an affected facility within 15 days after such date.

(b) Any owner or operator subject to the provisions of this part shall maintain for a period of 2 years a record of the occurrence and duration of any startup, shutdown, or malfunction in operation of any affected facility.

§ 60.8 Performance tests.

(a) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(b) Performance tests shall be conducted and results reported in accordance with the test method set forth in this part or equivalent methods approved by the Administrator; or where the Administrator determines that emissions from the affected facility are not susceptible of being measured by such methods, the Administrator shall prescribe alternative test procedures for determining compliance with the requirements of this part.

(c) The owner or operator shall permit the Administrator to conduct performance tests at any reasonable time, shall cause the affected facility to be operated for purposes of such tests under such conditions as the Administrator shall specify based on representative performance of the affected facility, and shall make available to the Administrator such records as may be necessary to determine such performance.

(d) The owner or operator of an affected facility shall provide the Administrator 10 days prior notice of the performance test to afford the Administrator the opportunity to have an observer present.

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform (s).

(4) Utilities for sampling and testing equipment.

(f) Each performance test shall consist of three repetitions of the applicable test method. For the purpose of determining compliance with an applicable standard of performance, the average of results of all repetitions shall apply.

§ 60.9 Availability of information.

(a) Emission data provided to, or otherwise obtained by, the Administrator in accordance with the provisions of this part shall be available to the public.

(b) Except as provided in paragraph (a) of this section, any records, reports, or information provided to, or otherwise obtained by, the Administrator in accordance with the provisions of this part shall be available to the public, except that (1) upon a showing satisfactory to the Administrator by any person that such records, reports, or information, or particular part thereof (other than emission data), if made public, would divulge methods or processes entitled to protection as trade secrets of such person, the Administrator shall consider such records, reports, or information, or particular part thereof, confidential in accordance with the purposes of section 1905 of title 18 of the United States Code, except that such records, reports, or information, or particular part thereof, may be disclosed to other officers, employees, or authorized representatives of the United States concerned with carrying out the provisions of the Act or when relevant in any proceeding under the Act; and (2) information received by the Administrator solely for the purposes of §§ 60.5 and 60.6 shall not be disclosed if it is identified by the owner or operator as being a trade secret or commercial or financial information which such owner or operator considers confidential.

§ 60.10 State authority.

The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from:

(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

Subpart D—Standards of Performance for Fossil-Fuel Fired Steam Generators

§ 60.40 Applicability and designation of affected facility.

The provisions of this subpart are applicable to each fossil fuel-fired steam generating unit of more than 250 million B.t.u. per hour heat input, which is the affected facility.

§ 60.41 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, and in Subpart A of this part.

(a) "Fossil fuel-fired steam generating unit" means a furnace or boiler used in the process of burning fossil fuel for the primary purpose of producing steam by heat transfer.

(b) "Fossil fuel" means natural gas, petroleum, coal and any form of solid, liquid, or gaseous fuel derived from such materials.

(c) "Particulate matter" means any finely divided liquid or solid material, other than uncombined water, as measured by Method 5.

§ 60.42 Standard for particulate matter.

On and after the date on which the performance test required to be conducted by § 60.8 is initiated no owner or operator subject to the provisions of this part shall discharge or cause the discharge into the atmosphere of particulate matter which is:

(a) In excess of 0.10 lb. per million B.t.u. heat input (0.18 g. per million cal.) maximum 2-hour average.

(b) Greater than 20 percent opacity, except that 40 percent opacity shall be permissible for not more than 2 minutes in any hour.

(c) Where the presence of uncombined water is the only reason for failure to meet the requirements of paragraph (b) of this section such failure shall not be a violation of this section.

§ 60.43 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by § 60.8 is initiated no owner or operator subject to the provisions of this part shall discharge or cause the discharge into the atmosphere of sulfur dioxide in excess of:

(a) 0.80 lb. per million B.t.u. heat input (1.4 g. per million cal.), maximum 2-hour average, when liquid fossil fuel is burned.

(b) 1.2 lbs. per million B.t.u. heat input (2.2 g. per million cal.), maximum 2-hour average, when solid fossil fuel is burned.

(c) Where different fossil fuels are burned simultaneously in any combination, the applicable standard shall be determined by proration. Compliance shall be determined using the following formula:

$$\frac{y(0.80)+z(1.2)}{x+y+z}$$

where:
x is the percent of total heat input derived from gaseous fossil fuel and,
y is the percent of total heat input derived from liquid fossil fuel and,
z is the percent of total heat input derived from solid fossil fuel.

§ 60.44 Standard for nitrogen oxides.

On and after the date on which the performance test required to be conducted by § 60.8 is initiated no owner or operator subject to the provisions of this part shall discharge or cause the discharge into the atmosphere of nitrogen oxides in excess of:

(a) 0.20 lb. per million B.t.u. heat input (0.36 g. per million cal.), maximum 2-hour average, expressed as NO_2, when gaseous fossil fuel is burned.

(b) 0.30 lb. per million B.t.u. heat input (0.54 g. per million cal.), maximum 2-hour average, expressed as NO_2, when liquid fossil fuel is burned.

(c) 0.70 lb. per million B.t.u. heat input (1.26 g. per million cal.), maximum 2-hour average, expressed as NO_2 when solid fossil fuel (except lignite) is burned.

(d) When different fossil fuels are burned simultaneously in any combination the applicable standard shall be determined by proration. Compliance shall be determined by using the following formula:

$$\frac{x(0.20)+y(0.30)+z(0.70)}{x+y+z}$$

where:
x is the percent of total heat input derived from gaseous fossil fuel and,
y is the percent of total heat input derived from liquid fossil fuel and,
z is the percent of total heat input derived from solid fossil fuel.

§ 60.45 Emission and fuel monitoring.

(a) There shall be installed, calibrated, maintained, and operated, in any fossil fuel-fired steam generating unit subject to the provisions of this part, emission monitoring instruments as follows:

(1) A photoelectric or other type smoke detector and recorder, except where gaseous fuel is the only fuel burned.

(2) An instrument for continuously monitoring and recording sulfur dioxide emissions, except where gaseous fuel is the only fuel burned, or where compliance is achieved through low sulfur fuels and representative sulfur analysis of fuels are conducted daily in accordance with paragraph (c) or (d) of this section.

(3) An instrument for continuously monitoring and recording emissions of nitrogen oxides.

(b) Instruments and sampling systems installed and used pursuant to this section shall be capable of monitoring emission levels within ±20 percent with a confidence level of 95 percent and shall be calibrated in accordance with the method(s) prescribed by the manufacturer(s) of such instruments; instruments shall be subjected to manufacturers recommended zero adjustment and calibration procedures at least once per 24-hour operating period unless the manufacturer(s) specifies or recommends calibration at shorter intervals, in which case such specifications or recommendations shall be followed. The applicable method specified in the appendix of this part shall be the reference method.

(c) The sulfur content of solid fuels, as burned, shall be determined in accordance with the following methods of the American Society for Testing and Materials.

(1) Mechanical sampling by Method D 2234065.

(2) Sample preparation by Method D 2013–65.

(3) Sample analysis by Method D 271–68.

(d) The sulfur content of liquid fuels, as burned, shall be determined in accordance with the American Society for Testing and Materials Methods D 1551–68, or D 129–64, or D 1552–64.

(e) The rate of fuel burned for each fuel shall be measured daily or at shorter intervals and recorded. The heating value and ash content of fuels shall be ascertained at least once per week and recorded. Where the steam generating unit is used to generate electricity, the average electrical output and the minimum and maximum hourly generation rate shall be measured and recorded daily.

(f) The owner or operator of any fossil fuel-fired steam generating unit subject to the provisions of this part shall maintain a file of all measurements required by this part. Appropriate measurements shall be reduced to the units of the applicable standard daily, and summarized monthly. The record of any such measurement(s) and summary shall be retained for at least 2 years following the date of such measurements and summaries.

§ 60.46 Test methods and procedures.

(a) The provisions of this section are applicable to performance tests for determining emissions of particulate matter, sulfur dioxide, and nitrogen oxides from fossil fuel-fired steam generating units.

(b) All performance tests shall be conducted while the affected facility is operating at or above the maximum steam production rate at which such facility will be operated and while fuels or combinations of fuels representative of normal operation are being burned and under such other relevant conditions as the Administrator shall specify based on representative performance of the affected facility.

(c) Test methods set forth in the appendix to this part or equivalent methods approved by the Administrator shall be used as follows:

(1) For each repetition, the average concentration of particulate matter shall be determined by using Method 5. Traversing during sampling by Method 5 shall be according to Method 1. The minimum sampling time shall be 2 hours, and minimum sampling volume shall be 60 ft.^{3} corrected to standard conditions on a dry basis.

(2) For each repetition, the SO_2 concentration shall be determined by using Method 6. The sampling site shall be the same as for determining volumetric flow rate. The sampling point in the duct shall be at the centroid of the cross section if the cross sectional area is less than 50 ft.^{2} or at a point no closer to the walls than 3 feet if the cross sectional area is 50 ft.^{2} or more. The sample shall be extracted at a rate proportional to the gas velocity at the sampling point. The minimum sampling time shall be 20 min. and minimum sampling volume shall be 0.75 ft.^{3} corrected to standard conditions. Two samples shall constitute one repetition and shall be taken at 1-hour intervals.

(3) For each repetition the NO_x concentration shall be determined by using Method 7. The sampling site and point shall be the same as for SO_2. The sampling time shall be 2 hours, and four samples shall be taken at 30-minute intervals.

(4) The volumetric flow rate of the total effluent shall be determined by using Method 2 and traversing according to Method 1. Gas analysis shall be performed by Method 3, and moisture content shall be determined by the condenser technique of Method 5.

(d) Heat input, expressed in B.t.u. per hour, shall be determined during each 2-hour testing period by suitable fuel flow meters and shall be confirmed by a material balance over the steam generation system.

(e) For each repetition, emissions, expressed in lb./10^6 B.t.u. shall be determined by dividing the emission rate in lb./hr. by the heat input. The emission rate shall be determined by the equation, lb./hr.$=Q_s \times c$ where. Q_s=volumetric flow rate of the total effluent in ft.^{3}/hr. at standard conditions, dry basis, as determined in accordance with paragraph (c) (4) of this section.

(1) For particulate matter, c=particulate concentration in lb./ft.^{3}, at determined in accordance with paragraph (c) (1) of this section, corrected to standard conditions, dry basis.

(2) For SO_2, $c=SO_2$ concentration in lb./ft.^{3}, as determined in accordance with paragraph (c)(2) of this section, corrected to standard conditions, dry basis.

(3) For NO_x, $c=NO_x$ concentration in lb./ft.^{3}, as determined in accordance with paragraph (c)(3) of this section, corrected to standard conditions, dry basis.

Subpart E—Standards of Performance for Incinerators

§ 60.50 Applicability and designation of affected facility.

The provisions of this subpart are applicable to each incinerator of more than 50 tons per day charging rate, which is the affected facility.

§ 60.51 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Incinerator" means any furnace used in the process of burning solid waste for the primary purpose of reducing the volume of the waste by removing combustible matter.

(b) "Solid waste" means refuse, more than 50 percent of which is municipal type waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustibles, and noncombustible materials such as glass and rock.

(c) "Day" means 24 hours.

(d) "Particulate matter" means any finely divided liquid or solid material, other than uncombined water, as measured by Method 5.

§ 60.52 Standard for particulate matter.

On and after the date on which the performance test required to be conducted by § 60.8 is initiated, no owner or operator subject to the provisions of this part shall discharge or cause the discharge into the atmosphere of particulate matter which is in excess of 0.08 gr./s.c.f. (0.18 g./NM^3) corrected to 12 percent CO_2, maximum 2-hour average.

§ 60.53 Monitoring of operations.

The owner or operator of any incinerator subject to the provisions of this part shall maintain a file of daily burning rates and hours of operation and any particulate emission measurements. The burning rates and hours of operation shall be summarized monthly. The record(s) and summary shall be retained for at least 2 years following the date of such records and summaries.

§ 60.54 Test methods and procedures.

(a) The provisions of this section are applicable to performance tests for determining emissions of particulate matter from incinerators.

(b) All performance tests shall be conducted while the affected facility is operating at or above the maximum refuse charging rate at which such facility will be operated and the solid waste burned shall be representative of normal operation and under such other relevant conditions as the Administrator shall specify based on representative performance of the affected facility.

(c) Test methods set forth in the appendix to this part or equivalent methods approved by the Administrator shall be used as follows:

(1) For each repetition, the average concentration of particulate matter shall be determined by using Method 5. Traversing during sampling by Method 5 shall be according to Method 1. The minimum sampling time shall be 2 hours and the minimum sampling volume shall be 60 ft.^{3} corrected to standard conditions on a dry basis.

(2) Gas analysis shall be performed using the integrated sample technique of Method 3, and moisture content shall be determined by the condenser technique of Method 5. If a wet scrubber is used, the gas analysis sample shall reflect flue gas conditions after the scrubber, allowing for the effect of carbon dioxide absorption.

(d) For each repetition particulate matter emissions, expressed in gr./s.c.f., shall be determined in accordance with paragraph (c)(1) of this section corrected to 12 percent CO_2, dry basis.

Subpart F—Standards of Performance for Portland Cement Plants

§ 60.60 Applicability and designation of affected facility.

The provisions of the subpart are applicable to the following affected facilities in portland cement plants: kiln, clinker cooler, raw mill system, finish mill system, raw mill dryer, raw material storage, clinker storage, finished product storage, conveyor transfer points, bagging and bulk loading and unloading systems.

§ 60.61 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Portland cement plant" means any facility manufacturing portland cement by either the wet or dry process.

(b) "Particulate matter" means any finely divided liquid or solid material, other than uncombined water, as measured by Method 5.

§ 60.62 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is initiated no owner or operator subject to the provisions of this part shall discharge or cause the discharge into the atmosphere of particulate matter from the kiln which is:

(1) In excess of 0.30 lb. per ton of feed to the kiln (0.15 Kg. per metric ton), maximum 2-hour average.

(2) Greater than 10 percent opacity, except that where the presence of uncombined water is the only reason for failure to meet the requirements for this subparagraph, such failure shall not be a violation of this section.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is initiated no owner or operator subject to the provisions of this part shall discharge or cause the discharge into the atmosphere of particulate matter from the clinker cooler which is:

(1) In excess of 0.10 lb. per ton of feed to the kiln (0.050 Kg. per metric ton) maximum 2-hour average.

(2) 10 percent opacity or greater.

(c) On and after the date on which the performance test required to be conducted by § 60.8 is initiated no owner or operator subject to the provisions of this part shall discharge or cause the discharge into the atmosphere of particulate matter from any affected facility other than the kiln and clinker cooler which is 10 percent opacity or greater.

§ 60.63 Monitoring of operations.

The owner or operator of any portland cement plant subject to the provisions of this part shall maintain a file of daily production rates and kiln feed rates and any particulate emission measurements. The production and feed rates shall be summarized monthly. The record(s) and summary shall be retained for at least 2 years following the date of such records and summaries.

§ 60.64 Test methods and procedures.

(a) The provisions of this section are applicable to performance tests for determining emissions of particulate matter from portland cement plant kilns and clinker coolers.

(b) All performance tests shall be conducted while the affected facility is operating at or above the maximum production rate at which such facility will be operated and under such other relevant conditions as the Administrator shall specify based on representative performance of the affected facility.

(c) Test methods set forth in the appendix to this part or equivalent methods approved by the Administrator shall be used as follows:

(1) For each repetition, the average concentration of particulate matter shall be determined by using Method 5. Traversing during sampling by Method 5 shall be according to Method 1. The minimum sampling time shall be 2 hours and the minimum sampling volume shall be 60 ft.^{3} corrected to standard conditions on a dry basis.

(2) The volumetric flow rate of the total effluent shall be determined by using Method 2 and traversing according to Method 1. Gas analysis shall be performed using the integrated sample technique of Method 3, and moisture content shall be determined by the condenser technique of Method 5.

(d) Total kiln feed (except fuels), expressed in tons per hour on a dry basis, shall be determined during each 2-hour testing period by suitable flow meters and shall be confirmed by a material balance over the production system.

(e) For each repetition, particulate matter emissions, expressed in lb./ton of kiln feed shall be determined by dividing the emission rate in lb./hr. by the kiln feed. The emission rate shall be determined by the equation, $lb./hr.=Q_s \times c$,

where Q_s=volumetric flow rate of the total effluent in ft.³/hr. at standard conditions, dry basis, as determined in accordance with paragraph (c)(2) of this section, and, c=particulate concentration in lb./ft.³, as determined in accordance with paragraph (c)(1) of this section, corrected to standard conditions, dry basis.

Subpart G—Standards of Performance for Nitric Acid Plants

§ 60.70 Applicability and designation of affected facility.

The provisions of this subpart are applicable to each nitric acid production unit, which is the affected facility.

§ 60.71 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Nitric acid production unit" means any facility producing weak nitric acid by either the pressure or atmospheric pressure process.

(b) "Weak nitric acid" means acid which is 30 to 70 percent in strength.

§ 60.72 Standard for nitrogen oxides.

On and after the date on which the performance test required to be conducted by § 60.8 is initiated no owner or operator subject to the provisions of this part shall discharge or cause the discharge into the atmosphere of nitrogen oxides which are:

(a) In excess of 3 lbs. per ton of acid produced (1.5 kg. per metric ton), maximum 2-hour average, expressed as NO_2.

(b) 10 percent opacity or greater.

§ 60.73 Emission monitoring.

(a) There shall be installed, calibrated, maintained, and operated, in any nitric acid production unit subject to the provisions of this subpart, an instrument for continuously monitoring and recording emissions of nitrogen oxides.

(b) The instrument and sampling system installed and used pursuant to this section shall be capable of monitoring emission levels within ±20 percent with a confidence level of 95 percent and shall be calibrated in accordance with the method(s) prescribed by the manufacturer(s) of such instrument, the instrument shall be subjected to manufacturers recommended zero adjustment and calibration procedures at least once per 24-hour operating period unless the manufacturer(s) specifies or recommends calibration at shorter intervals, in which case such specifications or recommendations shall be followed. The applicable method specified in the appendix of this part shall be the reference method.

(c) Production rate and hours of operation shall be recorded daily.

(d) The owner or operator of any nitric acid production unit subject to the provisions of this part shall maintain a file of all measurements required by this subpart. Appropriate measurements shall be reduced to the units of the standard daily and summarized monthly. The record of any such measurement and summary shall be retained for at least 2 years following the date of such measurements and summaries.

§ 60.74 Test methods and procedures.

(a) The provisions of this section are applicable to performance tests for determining emissions of nitrogen oxides from nitric acid production units.

(b) All performance tests shall be conducted while the affected facility is operating at or above the maximum acid production rate at which such facility will be operated and under such other relevant conditions as the Administrator shall specify based on representative performance of the affected facility.

(c) Test methods set forth in the appendix to this part or equivalent methods as approved by the Administrator shall be used as follows:

(1) For each repetition the NO_x concentration shall be determined by using Method 7. The sampling site shall be selected according to Method 1 and the sampling point shall be the centroid of the stack or duct. The sampling time shall be 2 hours and four samples shall be taken at 30-minute intervals.

(2) The volumetric flow rate of the total effluent shall be determined by using Method 2 and traversing according to Method 1. Gas analysis shall be performed by using the integrated sample technique of Method 3, and moisture content shall be determined by Method 4.

(d) Acid produced, expressed in tons per hour of 100 percent nitric acid, shall be determined during each 2-hour testing period by suitable flow meters and shall be confirmed by a material balance over the production system.

(e) For each repetition, nitrogen oxides emissions, expressed in lb./ton of 100 percent nitric acid, shall be determined by dividing the emission rate in lb./hr. by the acid produced. The emission rate shall be determined by the equation, lb./hr.=$Q_s \times c$, where Q_s=volumetric flow rate of the effluent in ft.³/hr. at standard conditions, dry basis, as determined in accordance with paragraph (c)(2) of this section, and c=NO_x concentration in lb./ft.³, as determined in accordance with paragraph (c)(1) of this section, corrected to standard conditions, dry basis.

Subpart H—Standards of Performance for Sulfuric Acid Plants

§ 60.80 Applicability and designation of affected facility.

The provisions of this subpart are applicable to each sulfuric acid production unit, which is the affected facility.

§ 60.81 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Sulfuric acid production unit" means any facility producing sulfuric acid by the contact process by burning elemental sulfur, alkylation acid, hydrogen sulfide, organic sulfides and mercaptans, or acid sludge, but does not include facilities where conversion to sulfuric acid is utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfur compounds.

(b) "Acid mist" means sulfuric acid mist, as measured by test methods set forth in this part.

§ 60.82 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by § 60.8 is initiated no owner or operator subject to the provisions of this part shall discharge or cause the discharge into the atmosphere of sulfur dioxide in excess of 4 lbs. per ton of acid produced (2 kg. per metric ton), maximum 2-hour average.

§ 60.83 Standard for acid mist.

On and after the date on which the performance test required to be conducted by § 60.8 is initiated no owner or operator subject to the provisions of this part shall discharge or cause the discharge into the atmosphere of acid mist which is:

(a) In excess of 0.15 lb. per ton of acid produced (0.075 kg. per metric ton), maximum 2-hour average, expressed as H_2SO_4.

(b) 10 percent opacity or greater.

§ 60.84 Emission monitoring.

(a) There shall be installed, calibrated, maintained, and operated, in any sulfuric acid production unit subject to the provisions of this subpart, an instrument for continuously monitoring and recording emissions of sulfur dioxide.

(b) The instrument and sampling system installed and used pursuant to this section shall be capable of monitoring emission levels within ±20 percent with a confidence level of 95 percent and shall be calibrated in accordance with the

method(s) prescribed by the manufacturer(s) of such instrument, the instrument shall be subject to manufacturers recommended zero adjustment calibration procedures at least once per 24-hour operating period unless the manufacturer(s) specified or recommends calibration at shorter intervals, in which case such specifications or recommendations shall be followed. The applicable method specified in the appendix of this part shall be the reference method.

(c) Production rate and hours of operation shall be recorded daily.

(d) The owner or operator of any sulfuric acid production unit subject to the provisions of this subpart shall maintain a file of all measurements required by this subpart. Appropriate measurements shall be reduced to the units of the applicable standard daily and summarized monthly. The record of any such measurement and summary shall be retained for at least 2 years following the date of such measurements and summaries.

§ 60.85 Test methods and procedures.

(a) The provisions of this section are applicable to performance tests for determining emissions of acid mist and sulfur dioxide from sulfuric acid production units.

(b) All performance tests shall be conducted while the affected facility is operating at or above the maximum acid production rate at which such facility will be operated and under such other relevant conditions as the Administrator shall specify based on representative performance of the affected facility.

(c) Test methods set forth in the appendix to this part or equivalent methods as approved by the Administrator shall be used as follows:

(1) For each repetition the acid mist and SO_3 concentrations shall be determined by using Method 8 and traversing according to Method 1. The minimum sampling time shall be 2 hours, and minimum sampling volume shall be 40 ft.^{3} corrected to standard conditions.

(2) The volumetric flow rate of the total effluent shall be determined by using Method 2 and traversing according to Method 1. Gas analysis shall be performed by using the integrated sample technique of Method 3. Moisture content can be considered to be zero.

(d) Acid produced, expressed in tons per hour of 100 percent sulfuric acid shall be determined during each 2-hour testing period by suitable flow meters and shall be confirmed by a material balance over the production system.

(e) For each repetition acid mist and sulfur dioxide emissions, expressed in lb./ton of 100 percent sulfuric acid shall be determined by dividing the emission rate in lb./hr. by the acid produced. The emission rate shall be determined by the equation, lb./hr.$=Q_s \times c$, where Q_s=volumetric flow rate of the effluent in ft.^{3}/hr. at standard conditions, dry basis as determined in accordance with paragraph (c)(2) of this section, and c=acid mist and SO_3 concentrations in lb./ft.^{3} as determined in accordance with paragraph (c)(1) of this section, corrected to standard conditions, dry basis.

APPENDIX—TEST METHODS

METHOD 1—SAMPLE AND VELOCITY TRAVERSES FOR STATIONARY SOURCES

1. *Principle and Applicability.*

1.1 Principle. A sampling site and the number of traverse points are selected to aid in the extraction of a representative sample.

1.2 Applicability. This method should be applied only when specified by the test procedures for determining compliance with the New Source Performance Standards. Unless otherwise specified, this method is not intended to apply to gas streams other than those emitted directly to the atmosphere without further processing.

2. *Procedure.*

2.1 Selection of a sampling site and minimum number of traverse points.

2.1.1 Select a sampling site that is at least eight stack or duct diameters downstream and two diameters upstream from any flow disturbance such as a bend, expansion, contraction, or visible flame. For rectangular cross section, determine an equivalent diameter from the following equation:

$$\text{equivalent diameter} = 2\left(\frac{(\text{length})(\text{width})}{\text{length}+\text{width}}\right)$$

equation 1-1

2.1.2 When the above sampling site criteria can be met, the minimum number of traverse points is twelve (12).

2.1.3 Some sampling situations render the above sampling site criteria impractical. When this is the case, choose a convenient sampling location and use Figure 1-1 to determine the minimum number of traverse points. Under no conditions should a sampling point be selected within 1 inch of the stack wall. To obtain the number of traverse points for stacks or ducts with a diameter less than 2 feet, multiply the number of points obtained from Figure 1-1 by 0.67.

2.1.4 To use Figure 1-1 first measure the distance from the chosen sampling location to the nearest upstream and downstream disturbances. Determine the corresponding number of traverse points for each distance from Figure 1-1. Select the higher of the two numbers of traverse points, or a greater value, such that for circular stacks the number is a multiple of 4, and for rectangular stacks the number follows the criteria of section 2.2.2.

2.2 Cross-sectional layout and location of traverse points.

2.2.1 For circular stacks locate the traverse points on at least two diameters according to Figure 1-2 and Table 1-1. The traverse axes shall divide the stack cross section into equal parts.

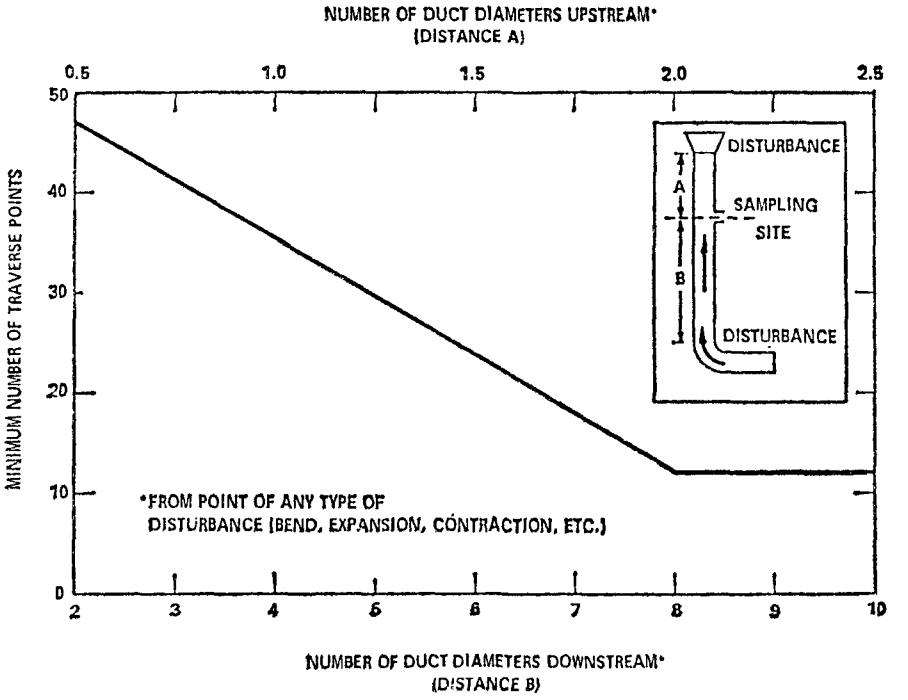


Figure 1-1. Minimum number of traverse points.

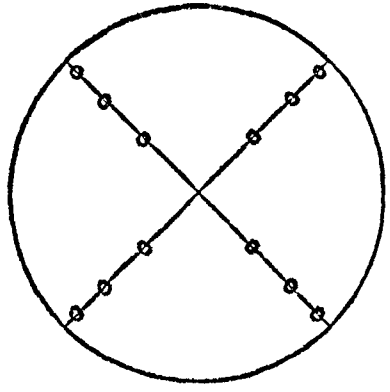


Figure 1-2. Cross section of circular stack divided into 12 equal areas, showing location of traverse points at centroid of each area.

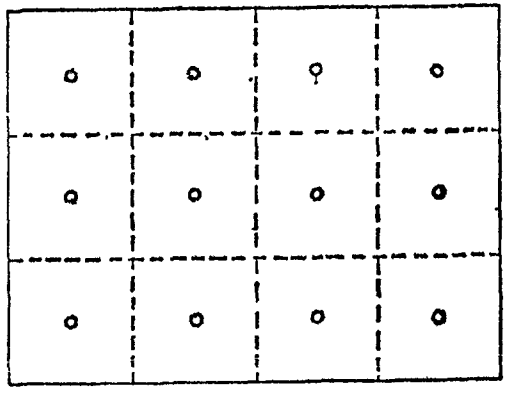


Figure 1-3. Cross section of rectangular stack divided into 12 equal areas, with traverse points at centroid of each area.

Table 1-1. Location of traverse points in circular stacks
(Percent of stack diameter from inside wall to traverse point)

Traverse point number on a diameter	Number of traverse points on a diameter											
	2	4	6	8	10	12	14	16	18	20	22	24
1	14.6	6.7	4.4	3.3	2.5	2.1	1.8	1.6	1.4	1.3	1.1	1.1
2	85.4	25.0	14.7	10.5	8.2	6.7	5.7	4.9	4.4	3.9	3.5	3.2
3		75.0	29.5	19.4	14.6	11.8	9.9	8.5	7.5	6.7	6.0	5.5
4		93.3	70.5	32.3	22.6	17.7	14.6	12.5	10.9	9.7	8.7	7.9
5			85.3	67.7	34.2	25.0	20.1	16.9	14.6	12.9	11.6	10.5
6			95.6	80.6	65.8	35.5	26.9	22.0	18.8	16.5	14.6	13.2
7				89.5	77.4	64.5	36.6	28.3	23.6	20.4	18.0	16.1
8				96.7	85.4	65.0	63.4	37.5	29.6	25.0	21.8	19.4
9					91.8	82.3	73.1	62.5	38.2	30.6	26.1	23.0
10					97.5	88.2	79.9	71.7	61.8	38.8	31.5	27.2
11						93.3	85.4	78.0	70.4	61.2	39.3	32.3
12						97.9	90.1	83.1	76.4	69.4	60.7	39.8
13							94.3	87.5	81.2	75.0	68.5	60.2
14							98.2	91.5	85.4	79.6	73.9	67.7
15								95.1	89.1	83.5	78.2	72.8
16								98.4	92.5	87.1	82.0	77.0
17									95.6	90.3	85.4	80.6
18									98.6	93.3	88.4	83.9
19										96.1	91.3	86.8
20										98.7	94.0	89.5
21											96.5	92.1
22											98.9	94.5
23												96.8
24												98.9

2.2.2 For rectangular stacks divide the cross section into as many equal rectangular areas as traverse points, such that the ratio of the length to the width of the elemental areas is between one and two. Locate the traverse points at the centroid of each equal area according to Figure 1-3.

3. *References.*

Determining Dust Concentration in a Gas Stream, ASME Performance Test Code #27, New York, N.Y., 1957.

Devorkin, Howard, et al., Air Pollution Source Testing Manual, Air Pollution Control District, Los Angeles, Calif. November 1963.

Methods for Determination of Velocity, Volume, Dust and Mist Content of Gases, Western Precipitation Division of Joy Manufacturing Co., Los Angeles, Calif. Bulletin WP-50, 1968.

Standard Method for Sampling Stacks for Particulate Matter, In: 1971 Book of ASTM Standards, Part 23, Philadelphia, Pa. 1971, ASTM Designation D-2928-71.

METHOD 2—DETERMINATION OF STACK GAS VELOCITY AND VOLUMETRIC FLOW RATE (TYPE S PITOT TUBE)

1. *Principle and applicability.*

1.1 Principle. Stack gas velocity is determined from the gas density and from measurement of the velocity head using a Type S (Stauscheibe or reverse type) pitot tube.

1.2 Applicability. This method should be applied only when specified by the test procedures for determining compliance with the New Source Performance Standards.

2. *Apparatus.*

2.1 Pitot tube—Type S (Figure 2-1), or equivalent, with a coefficient within ±5% over the working range.

2.2 Differential pressure gauge—Inclined manometer, or equivalent, to measure velocity head to within 10% of the minimum value.

2.3 Temperature gauge—Thermocouple or equivalent attached to the pitot tube to measure stack temperature to within 1.5% of the minimum absolute stack temperature.

2.4 Pressure gauge—Mercury-filled U-tube manometer, or equivalent, to measure stack pressure to within 0.1 in. Hg.

2.5 Barometer—To measure atmospheric pressure to within 0.1 in. Hg.

2.6 Gas analyzer—To analyze gas composition for determining molecular weight.

2.7 Pitot tube—Standard type, to calibrate Type S pitot tube.

3. *Procedure.*

3.1 Set up the apparatus as shown in Figure 2-1. Make sure all connections are tight and leak free. Measure the velocity head and temperature at the traverse points specified by Method 1.

3.2 Measure the static pressure in the stack.

3.3 Determine the stack gas molecular weight by gas analysis and appropriate calculations as indicated in Method 3.

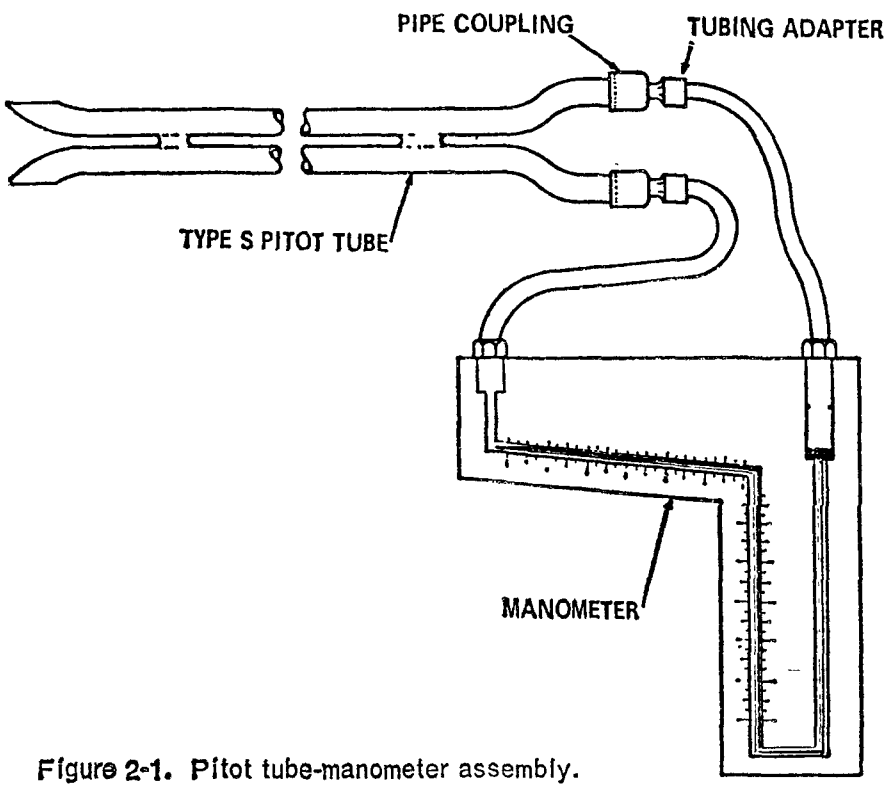


Figure 2-1. Pitot tube-manometer assembly.

4. *Calibration.*

4.1 To calibrate the pitot tube, measure the velocity head at some point in a flowing gas stream with both a Type S pitot tube and a standard type pitot tube with known coefficient. Calibration should be done in the laboratory and the velocity of the flowing gas stream should be varied over the normal working range. It is recommended that the calibration be repeated after use at each field site.

4.2 Calculate the pitot tube coefficient using equation 2-1.

$$C_{p_{test}} = C_{p_{std}} \sqrt{\frac{\Delta p_{std}}{\Delta p_{test}}} \quad \text{equation 2-1}$$

where:

$C_{p_{test}}$ = Pitot tube coefficient of Type S pitot tube.

$C_{p_{std}}$ = Pitot tube coefficient of standard type pitot tube (if unknown, use 0.99).

Δp_{std} = Velocity head measured by standard type pitot tube.

Δp_{test} = Velocity head measured by Type S pitot tube.

4.3 Compare the coefficients of the Type S pitot tube determined first with one leg and then the other pointed downstream. Use the pitot tube only if the two coefficients differ by no more than 0.01.

5. *Calculations.*

Use equation 2-2 to calculate the stack gas velocity.

$$(V_s)_{avg.} = K_p C_p (\sqrt{\Delta p})_{avg.} \sqrt{\frac{(T_s)_{avg.}}{P_s M_s}}$$

Equation 2-2

where:

$(V_s)_{avg}$ = Stack gas velocity, feet per second (f.p.s.).

$K_p = 85.48 \frac{\text{ft.}}{\text{sec.}} \left(\frac{\text{lb.}}{\text{lb. mole-°R}}\right)^{1/2}$ when these units are used.

C_p = Pitot tube coefficient, dimensionless.

$(T_s)_{avg.}$ = Average absolute stack gas temperature, °R.

$(\sqrt{\Delta p})_{avg}$ = Average velocity head of stack gas, inches H_2O (see Fig. 2-2).

P_s = Absolute stack gas pressure, inches Hg.

M_s = Molecular weight of stack gas (wet basis), lb./lb.-mole.

$M_d(1-B_{wo})+18B_{wo}$

M_d = Dry molecular weight of stack gas (from Method 3).

B_{wo} = Proportion by volume of water vapor in the gas stream (from Method 4).

Figure 2-2 shows a sample recording sheet for velocity traverse data. Use the averages in the last two columns of Figure 2-2 to determine the average stack gas velocity from Equation 2-2.

Use Equation 2-3 to calculate the stack gas volumetric flow rate.

$$Q_s = 3600\ (1-B_{wo})\ V_s A \left(\frac{T_{std}}{(T_s)_{avg.}}\right)\left(\frac{P_s}{P_{std}}\right)$$

Equation 2-3

where:

Q_s = Volumetric flow rate, dry basis, standard conditions, ft.³/hr.

A = Cross-sectional area of stack, ft.²

T_{std} = Absolute temperature at standard conditions, 530° R.

P_{std} = Absolute pressure at standard conditions, 29.92 inches Hg.

6. *References.*

Mark, L. S., Mechanical Engineers' Handbook, McGraw-Hill Book Co., Inc., New York, N.Y., 1951.

Perry, J. H., Chemical Engineers' Handbook, McGraw-Hill Book Co., Inc., New York, N.Y., 1960.

Shigehara, R. T., W. F. Todd, and W. S. Smith, Significance of Errors in Stack Sampling Measurements. Paper presented at the Annual Meeting of the Air Pollution Control Association, St. Louis, Mo., June 14–19, 1970.

Standard Method for Sampling Stacks for Particulate Matter, In: 1971 Book of ASTM Standards, Part 23, Philadelphia, Pa., 1971, ASTM Designation D–2928–71.

Vennard, J. K., Elementary Fluid Mechanics, John Wiley & Sons, Inc., New York, N.Y., 1947.

PLANT_____

DATE_____

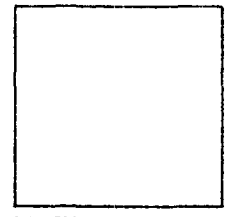
RUN NO._____

STACK DIAMETER, in._____

BAROMETRIC PRESSURE, in. Hg._____

STATIC PRESSURE IN STACK (P_g), in. Hg._____

OPERATORS_____



SCHEMATIC OF STACK CROSS SECTION

Traverse point number	Velocity head, in. H_2O	$\sqrt{\Delta_P}$	Stack Temperature (T_S), °F
	AVERAGE:		

Figure 2-2. Velocity traverse data.

METHOD 3—GAS ANALYSIS FOR CARBON DIOXIDE, EXCESS AIR, AND DRY MOLECULAR WEIGHT

1. *Principle and applicability.*

1.1 Principle. An integrated or grab gas sample is extracted from a sampling point and analyzed for its components using an Orsat analyzer.

1.2 Applicability. This method should be applied only when specified by the test procedures for determining compliance with the New Source Performance Standards. The test procedure will indicate whether a grab sample or an integrated sample is to be used.

2. *Apparatus.*

2.1 Grab sample (Figure 3-1).

2.1.1 Probe—Stainless steel or Pyrex[1] glass, equipped with a filter to remove particulate matter.

2.1.2 Pump—One-way squeeze bulb, or equivalent, to transport gas sample to analyzer.

[1] Trade name.

2.2 *Integrated sample (Figure 3-2).*

2.2.1 Probe—Stainless steel or Pyrex[1] glass, equipped with a filter to remove particulate matter.

2.2.2 Air-cooled condenser or equivalent—To remove any excess moisture.

2.2.3 Needle valve—To adjust flow rate.

2.2.4 Pump—Leak-free, diaphragm type, or equivalent, to pull gas.

2.2.5 Rate meter—To measure a flow range from 0 to 0.035 cfm.

2.2.6 Flexible bag—Tedlar,[1] or equivalent, with a capacity of 2 to 3 cu. ft. Leak test the bag in the laboratory before using.

2.2.7 Pitot tube—Type S, or equivalent, attached to the probe so that the sampling flow rate can be regulated proportional to the stack gas velocity when velocity is varying with time or a sample traverse is conducted.

2.3 *Analysis.*

2.3.1 Orsat analyzer, or equivalent.

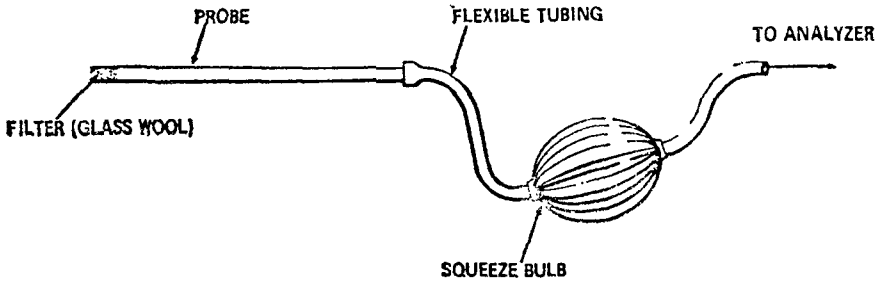


Figure 3-1. Grab-sampling train.

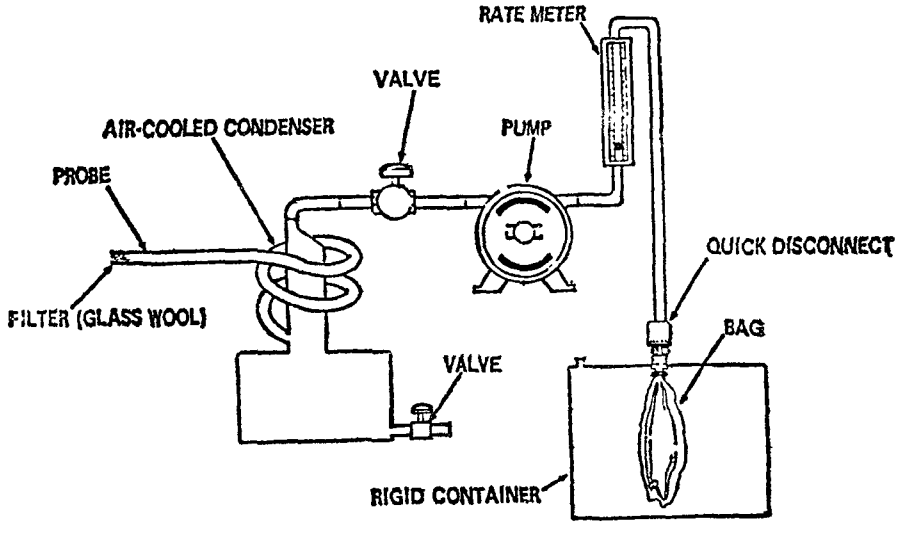


Figure 3-2. Integrated gas - sampling train.

3. *Procedure.*

3.1 Grab sampling.

3.1.1 Set up the equipment as shown in Figure 3-1, making sure all connections are leak-free. Place the probe in the stack at a sampling point and purge the sampling line.

3.1.2 Draw sample into the analyzer.

3.2 Integrated sampling.

3.2.1 Evacuate the flexible bag. Set up the equipment as shown in Figure 3-2 with the bag disconnected. Place the probe in the stack and purge the sampling line. Connect the bag, making sure that all connections are tight and that there are no leaks.

3.2.2 Sample at a rate proportional to the stack velocity.

3.3 Analysis.

3.3.1 Determine the CO_2, O_2, and CO concentrations as soon as possible. Make as many passes as are necessary to give constant readings. If more than ten passes are necessary, replace the absorbing solution.

3.3.2 For grab sampling, repeat the sampling and analysis until three consecutive samples vary no more than 0.5 percent by volume for each component being analyzed.

3.3.3 For integrated sampling, repeat the analysis of the sample until three consecutive analyses vary no more than 0.2 percent by volume for each component being analyzed.

4. *Calculations.*

4.1 Carbon dioxide. Average the three consecutive runs and report the result to the nearest 0.1% CO_2.

4.2 Excess air. Use Equation 3-1 to calculate excess air, and average the runs. Report the result to the nearest 0.1% excess air.

$$\%\,EA = \frac{(\%\,O_2) - 0.5(\%\,CO)}{0.264(\%\,N_2) - (\%\,O_2) + 0.5(\%\,CO)} \times 100$$

equation 3-1

where:

%EA = Percent excess air.

$\%O_2$ = Percent oxygen by volume, dry basis.

$\%N_2$ = Percent nitrogen by volume, dry basis.

%CO = Percent carbon monoxide by volume, dry basis.

0.264 = Ratio of oxygen to nitrogen in air by volume.

4.3 Dry molecular weight. Use Equation 3-2 to calculate dry molecular weight and average the runs. Report the result to the nearest tenth.

$$M_d = 0.44(\%\,CO_2) + 0.32(\%\,O_2) + 0.28(\%\,N_2 + \%\,CO)$$

equation 3-2

where:

M_d = Dry molecular weight, lb./lb-mole.

$\%CO_2$ = Percent carbon dioxide by volume, dry basis.

$\%O_2$ = Percent oxygen by volume, dry basis.

$\%N_2$ = Percent nitrogen by volume, dry basis.

0.44 = Molecular weight of carbon dioxide divided by 100.

0.32 = Molecular weight of oxygen divided by 100.

0.28 = Molecular weight of nitrogen and CO divided by 100.

5. *References.*

Altshuller, A. P., et al., Storage of Gases and Vapors in Plastic Bags, Int. J. Air & Water Pollution, 6:75–81, 1963.

Conner, William D., and J. S. Nader, Air Sampling with Plastic Bags, Journal of the American Industrial Hygiene Association, 25:291–297, May–June 1964.

Devorkin, Howard, et al., Air Pollution Source Testing Manual, Air Pollution Control District, Los Angeles, Calif., November 1963.

METHOD 4—DETERMINATION OF MOISTURE IN STACK GASES

1. *Principle and applicability.*

1.1 Principle. Moisture is removed from the gas stream, condensed, and determined volumetrically.

1.2 Applicability. This method is applicable for the determination of moisture in stack gas only when specified by test procedures for determining compliance with New Source Performance Standards. This method does not apply when liquid droplets are present in the gas stream[1] and the moisture is subsequently used in the determination of stack gas molecular weight.

Other methods such as drying tubes, wet bulb-dry bulb techniques, and volumetric condensation techniques may be used.

2. *Apparatus.*

2.1 Probe—Stainless steel or Pyrex[2] glass sufficiently heated to prevent condensation and equipped with a filter to remove particulate matter.

2.2 Impingers—Two midget impingers, each with 30 ml. capacity, or equivalent.

2.3 Ice bath container—To condense moisture in impingers.

2.4 Silica gel tube (optional)—To protect pump and dry gas meter.

2.5 Needle valve—To regulate gas flow rate.

2.6 Pump—Leak-free, diaphragm type, or equivalent, to pull gas through train.

2.7 Dry gas meter—To measure to within 1% of the total sample volume.

2.8 Rotameter—To measure a flow range from 0 to 0.1 c.f.m.

2.9 Graduated cylinder—25 ml.

2.10 Barometer—Sufficient to read to within 0.1 inch Hg.

2.11 Pitot tube—Type S, or equivalent, attached to probe so that the sampling flow rate can be regulated proportional to the stack gas velocity when velocity is varying with time or a sample traverse is conducted.

3. *Procedure.*

3.1 Place exactly 5 ml. distilled water in each impinger. Assemble the apparatus without the probe as shown in Figure 4-1. Leak check by plugging the inlet to the first impinger and drawing a vacuum. Insure that flow through the dry gas meter is less than 1% of the sampling rate.

3.2 Connect the probe and sample at a constant rate of 0.075 c.f.m. or at a rate proportional to the stack gas velocity. Continue sampling until the dry gas meter registers 1 cubic foot or until visible liquid droplets are carried over from the first impinger to the second. Record temperature, pressure, and dry gas meter readings as required by Figure 4-2.

3.3 After collecting the sample, measure the volume increase to the nearest 0.5 ml.

4. *Calculations.*

4.1 Volume of water vapor collected.

$$V_{wc}=\frac{(V_f-V_i)\rho_{H_2O}RT_{std}}{P_{std}M_{H_2O}}-0.0474\frac{\text{ft.}^3}{\text{ml.}}(V_f-V_i) \qquad \text{equation 4-1}$$

where:

V_{wc}=Volume of water vapor collected (standard conditions), cu. ft

V_f=Final volume of impinger contents, ml.

V_i=Initial volume of impinger contents, ml.

R=Ideal gas constant, 21.83 inches Hg—cu. ft./lb. mole-°R.

ρ_{H_2O}=Density of water, 1 g./ml.

T_{std}=Absolute temperature at standard conditions, 530° R.

P_{std}=Absolute pressure at standard conditions, 29.92 inches Hg.

M_{H_2O}=Molecular weight of water, 18 lb./lb.-mole.

[1] If liquid droplets are present in the gas stream, assume the stream to be saturated, determine the average stack gas temperature by traversing according to Method 1, and use a psychrometric chart to obtain an approximation of the moisture percentage.

[2] Trade name.

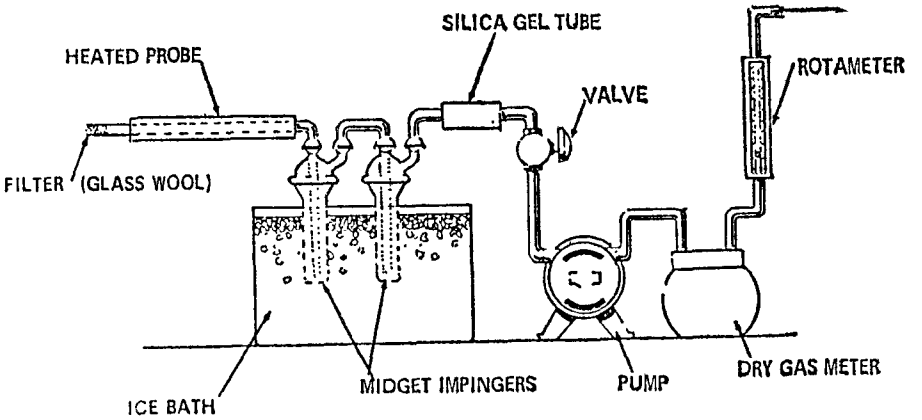


Figure 4-1. Moisture-sampling train.

LOCATION _____ COMMENTS

TEST _____

DATE _____

OPERATOR _____

BAROMETRIC PRESSURE _____

CLOCK TIME	GAS VOLUME THROUGH METER, (Vm), ft^3	ROTAMETER SETTING ft^3/min	METER TEMPERATURE, °F

Figure 4-2. Field moisture determination.

4.2 Gas volume.

$$V_{mc}=V_m\left(\frac{P_m}{P_{std}}\right)\left(\frac{T_{std}}{T_m}\right)=17.71\ \frac{^\circ R}{\text{in. Hg}}\left(\frac{V_m P_m}{T_m}\right) \quad \text{equation 4-2}$$

where:

V_{mc} = Dry gas volume through meter at standard conditions, cu. ft.
V_m = Dry gas volume measured by meter, cu. ft.
P_m = Barometric pressure at the dry gas meter, inches Hg.
P_{std} = Pressure at standard conditions, 29.92 inches Hg.
T_{std} = Absolute temperature at standard conditions, 530° R.
T_m = Absolute temperature at meter (°F + 460), °R.

4.3 Moisture content.

$$B_{wc}=\frac{V_{wc}}{V_{wc}+V_{mc}}+B_{wm}=\frac{V_{wc}}{V_{wc}+V_{mc}}+(0.025) \quad \text{equation 4-3}$$

where:

B_{wc} = Proportion by volume of water vapor in the gas stream, dimensionless.
V_{wc} = Volume of water vapor collected (standard conditions), cu. ft.
V_{mc} = Dry gas volume through meter (standard conditions), cu. ft.
B_{wm} = Approximate volumetric proportion of water vapor in the gas stream leaving the impingers, 0 025.

5. *References.*

Air Pollution Engineering Manual, Danielson, J. A. (ed.), U.S. DHEW, PHS, National Center for Air Pollution Control, Cincinnati, Ohio, PHS Publication No. 999–AP–40, 1967.

Devorkin, Howard, et al., Air Pollution Source Testing Manual, Air Pollution Control District, Los Angeles, Calif., November 1963.

Methods for Determination of Velocity, Volume, Dust and Mist Content of Gases, Western Precipitation Division of Joy Manufacturing Co., Los Angeles, Calif., Bulletin WP–50, 1968.

METHOD 5—DETERMINATION OF PARTICULATE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and applicability.*

1.1 Principle. Particulate matter is withdrawn isokinetically from the source and its weight is determined gravimetrically after removal of uncombined water.

1.2 Applicability. This method is applicable for the determination of particulate emissions from stationary sources only when specified by the test procedures for determining compliance with New Source Performance Standards.

2. *Apparatus.*

2.1 Sampling train. The design specifications of the particulate sampling train used by EPA (Figure 5–1) are described in APTD–0531. Commercial models of this train are available.

2.1.1 Nozzle—Stainless steel (316) with sharp, tapered leading edge.

2.1.2 Probe—Pyrex[1] glass with a heating system capable of maintaining a minimum gas temperature of 250° F. at the exit end during sampling to prevent condensation from occurring. When length limitations (greater than about 8 ft.) are encountered at temperatures less than 600° F., Incoloy 825[1], or equivalent, may be used. Probes for sampling gas streams at temperatures in excess of 600° F. must have been approved by the Administrator.

2.1.3 Pitot tube—Type S, or equivalent, attached to probe to monitor stack gas velocity.

[1] Trade name.

2.1.4 Filter Holder—Pyrex[1] glass with heating system capable of maintaining minimum temperature of 225° F.

2.1.5 Impingers / Condenser—Four impingers connected in series with glass ball joint fittings. The first, third, and fourth impingers are of the Greenburg-Smith design, modified by replacing the tip with a ½-inch ID glass tube extending to one-half inch from the bottom of the flask. The second impinger is of the Greenburg-Smith design with the standard tip. A condenser may be used in place of the impingers provided that the moisture content of the stack gas can still be determined.

2.1.6 *Metering system*—Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 5° F., dry gas meter with 2% accuracy, and related equipment, or equivalent, as required to maintain an isokinetic sampling rate and to determine sample volume.

2.1.7 Barometer—To measure atmospheric pressure to ±0.1 inches Hg.

2.2 Sample recovery.

2.2.1 Probe brush—At least as long as probe.

2.2.2 Glass wash bottles—Two.

2.2.3 Glass sample storage containers.

2.2.4 Graduated cylinder—250 ml.

2.3 Analysis.

2.3.1 Glass weighing dishes.

2.3.2 Desiccator.

2.3.3 Analytical balance—To measure to ±0.1 mg.

2.3.4 Trip balance—300 g. capacity to measure to ±0.05 g.

3. *Reagents.*

3.1 Sampling.

3.1.1 Filters—Glass fiber, MSA 1106 Bh[1], or equivalent, numbered for identification and preweighed.

3.1.2 Silica gel—Indicating type, 6–16 mesh, dried at 175° C. (350° F.) for 2 hours.

3.1.3 Water.

3.1.4 Crushed ice.

3.2 Sample recovery.

3.2.1 Acetone—Reagent grade.

3.3 Analysis.

3.3.1 Water.

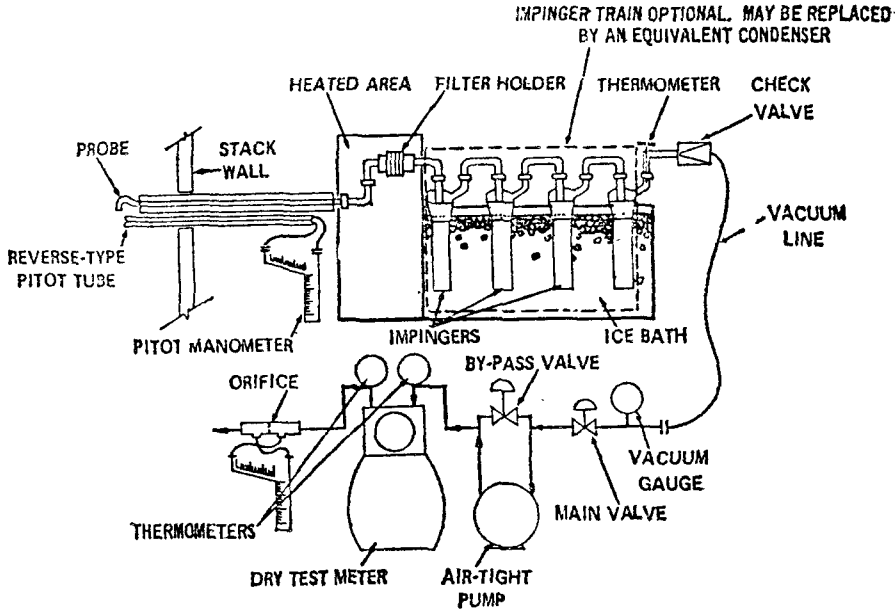


Figure 5-1. Particulate-sampling train.

3.3.2 Desiccant—Drierite,[1] indicating.

4. *Procedure.*

4.1 Sampling

4.1.1 *After* selecting the sampling site and the minimum number of sampling points, determine the stack pressure, temperature, moisture, and range of velocity head.

4.1.2 Preparation of collection train. Weigh to the nearest gram approximately 200 g. of silica gel. Label a filter of proper diameter, desiccate[2] for at least 24 hours and weigh to the nearest 0.5 mg. in a room where the relative humidity is less than 50%. Place 100 ml. of water in each of the first two impingers, leave the third impinger empty, and place approximately 200 g. of preweighed silica gel in the fourth impinger. Set up the train without the probe as in Figure 5–1. Leak check the sampling train at the sampling site by plugging up the inlet to the filter holder and pulling a 15 in. Hg vacuum. A leakage rate not in excess of 0.02 c.f.m. at a vacuum of 15 in. Hg is acceptable. Attach the probe and adjust the heater to provide a gas temperature of about 250° F. at the probe outlet. Turn on the filter heating system. Place crushed ice around the impingers. Add more ice during the run to keep the temperature of the gases leaving the last impinger as low as possible and preferably at 70° F., or less. Temperatures above 70° F. may result in damage to the dry gas meter from either moisture condensation or excessive heat.

4.1.3 Particulate train operation. For each run, record the data required on the example sheet shown in Figure 5–2. Take readings at each sampling point, at least every 5 minutes, and when significant changes in stack conditions necessitate additional adjustments in flow rate. To begin sampling, position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. Sample for at least 5 minutes at each traverse point; sampling time must be the same for each point. Maintain isokinetic sampling throughout the sampling period. Nomographs are available which aid in the rapid adjustment of the sampling rate without other computations. APTD–0576 details the procedure for using these nomographs. Turn off the pump at the conclusion of each run and record the final readings. Remove the probe and nozzle from the stack and handle in accordance with the sample recovery process described in section 4.2.

[1] Trade name.
[2] Dry using Drierite[1] at 70° F. ± 10° F.

PLANT_____
LOCATION_____
OPERATOR_____
DATE_____
RUN NO._____
SAMPLE BOX NO._____
METER BOX NO._____
METER $\Delta H_@$_____
C FACTOR_____

SCHEMATIC OF STACK CROSS SECTION

AMBIENT TEMPERATURE_____
BAROMETRIC PRESSURE_____
ASSUMED MOISTURE, %_____
HEATER BOX SETTING_____
PROBE LENGTH, in._____
NOZZLE DIAMETER, in._____
PROBE HEATER SETTING_____

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	STATIC PRESSURE (P_g), in. Hg	STACK TEMPERATURE (T_s), °F	VELOCITY HEAD (ΔP_s),	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER (ΔH), in. H_2O	GAS SAMPLE VOLUME (V_m), ft^3	GAS SAMPLE TEMPERATURE AT DRY GAS METER		SAMPLE BOX TEMPERATURE, °F	TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °F
							INLET ($T_{m_{in}}$), °F	OUTLET ($T_{m_{out}}$), °F		
TOTAL							Avg.	Avg.		
AVERAGE							Avg.			

Figure 5-2. Particulate field data.

4.2 Sample recovery. Exercise care in moving the collection train from the test site to the sample recovery area to minimize the loss of collected sample or the gain of extraneous particulate matter. Set aside a portion of the acetone used in the sample recovery as a blank for analysis. Measure the volume of water from the first three impingers, then discard. Place the samples in containers as follows:

Container No. 1. Remove the filter from its holder, place in this container, and seal.

Container No. 2. Place loose particulate matter and acetone washings from all sample-exposed surfaces prior to the filter in this container and seal. Use a razor blade, brush, or rubber policeman to lose adhering particles.

Container No. 3. Transfer the silica gel from the fourth impinger to the original container and seal. Use a rubber policeman as an aid in removing silica gel from the impinger.

4.3 Analysis. Record the data required on the example sheet shown in Figure 5-3. Handle each sample container as follows:

Container No. 1. Transfer the filter and any loose particulate matter from the sample container to a tared glass weighing dish, desiccate, and dry to a constant weight. Report results to the nearest 0.5 mg.

Container No. 2. Transfer the acetone washings to a tared beaker and evaporate to dryness at ambient temperature and pressure. Desiccate and dry to a constant weight. Report results to the nearest 0.5 mg.

Container No. 3. Weigh the spent silica gel and report to the nearest gram.

5. *Calibration.*

Use methods and equipment which have been approved by the Administrator to calibrate the orifice meter, pitot tube, dry gas meter, and probe heater. Recalibrate after each test series.

6. *Calculations.*

6.1 Average dry gas meter temperature and average orifice pressure drop. See data sheet (Figure 5-2).

6.2 Dry gas volume. Correct the sample volume measured by the dry gas meter to standard conditions (70° F., 29.92 inches Hg) by using Equation 5-1.

$$V_{m_{std}} = V_m \left(\frac{T_{std}}{T_m}\right)\left(\frac{P_{bar} + \frac{\Delta H}{13.6}}{P_{std}}\right) = \left(17.71 \frac{°R}{\text{in. Hg}}\right) V_m \left(\frac{P_{bar} + \frac{\Delta H}{13.6}}{T_m}\right)$$

equation 5-1

where:

$V_{m_{std}}$ = Volume of gas sample through the dry gas meter (standard conditions), cu. ft.

V_m = Volume of gas sample through the dry gas meter (meter conditions), cu. ft.

T_{std} = Absolute temperature at standard conditions, 530° R.

T_m = Average dry gas meter temperature, °R.

P_{bar} = Barometric pressure at the orifice meter, inches Hg.

ΔH = Average pressure drop across the orifice meter, inches H_2O.

13.6 = Specific gravity of mercury.

P_{std} = Absolute pressure at standard conditions, 29.92 inches Hg.

6.3 Volume of water vapor.

$$V_{w_{std}} = V_{l_c}\left(\frac{\rho_{H_2O}}{M_{H_2O}}\right)\left(\frac{RT_{std}}{P_{std}}\right) = \left(0.0474 \frac{\text{cu. ft.}}{\text{ml.}}\right) V_l$$

equation 5-2

where:

$V_{w_{std}}$ = Volume of water vapor in the gas sample (standard conditions), cu. ft.

V_{l_c} = Total volume of liquid collected in impingers and silica gel (see Figure 5-3), ml.

ρ_{H_2O} = Density of water, 1 g./ml.

M_{H_2O} = Molecular weight of water, 18 lb./lb.-mole.

R = Ideal gas constant, 21.83 inches Hg—cu. ft./lb.-mole-°R.

T_{std} = Absolute temperature at standard conditions, 530° R.

P_{std} = Absolute pressure at standard conditions, 29.92 inches Hg.

6.4 Moisture content.

$$B_{wo} = \frac{V_{w_{std}}}{V_{m_{std}} + V_{w_{std}}}$$

equation 5-3

where:

B_{wo} = Proportion by volume of water vapor in the gas stream, dimensionless.

$V_{w_{std}}$ = Volume of water in the gas sample (standard conditions), cu. ft.

$V_{m_{std}}$ = Volume of gas sample through the dry gas meter (standard conditions), cu. ft.

6.5 Total particulate weight. Determine the total particulate catch from the sum of the weights on the analysis data sheet (Figure 5-3).

6.6 Concentration.

6.6.1 Concentration in gr./s.c.f.

$$c'_s = \left(0.0154 \frac{\text{gr.}}{\text{mg.}}\right)\left(\frac{M_n}{V_{m_{std}}}\right)$$

equation 5-4

where:

c'_s = Concentration of particulate matter in stack gas, gr./s.c.f., dry basis.

M_n = Total amount of particulate matter collected, mg.

$V_{m_{std}}$ = Volume of gas sample through dry gas meter (standard conditions), cu. ft.

PLANT _____

DATE _____

RUN NO. _____

CONTAINER NUMBER	WEIGHT OF PARTICULATE COLLECTED, mg		
	FINAL WEIGHT	TARE WEIGHT	WEIGHT GAIN
1			
2			
TOTAL			

	VOLUME OF LIQUID WATER COLLECTED		
	IMPINGER VOLUME, ml	SILICA GEL WEIGHT, g	
FINAL			
INITIAL			
LIQUID COLLECTED			
TOTAL VOLUME COLLECTED		g*	ml

CONVERT WEIGHT OF WATER TO VOLUME BY DIVIDING TOTAL WEIGHT INCREASE BY DENSITY OF WATER. (1 g ml):

$$\frac{\text{INCREASE, g}}{(1\ \text{g/ml})} = \text{VOLUME WATER, ml}$$

Figure 5-3. Analytical data.

6.6.2 Concentration in lb./cu. ft.

$$c_s = \frac{\left(\frac{1}{453{,}600}\ \frac{\text{lb.}}{\text{mg.}}\right) M_n}{V_{m_{std}}} = 2.205 \times 10^{-6} \frac{M_n}{V_{m_{std}}} \qquad \text{equation 5-5}$$

where:

c_s = Concentration of particulate matter in stack gas, lb./s.c.f., dry basis.

453,600 = Mg/lb.

M_n = Total amount of particulate matter collected, mg.

$V_{m_{std}}$ = Volume of gas sample through dry gas meter (standard conditions), cu. ft.

6.7 Isokinetic variation.

$$I = \frac{T_s\left[\frac{V_{l_c}(\rho_{H_2O})R}{M_{H_2O}} + \frac{V_m}{T_m}\left(P_{bar} + \frac{\Delta H}{13.6}\right)\right]}{\theta V_s P_s A_n} \times 100$$

$$= \frac{\left(1.667\frac{\text{min.}}{\text{sec.}}\right)\left[\left(0.00267\frac{\text{in. Hg-cu. ft.}}{\text{ml.-°R}}\right)V_{l_c} + \frac{V_m}{T_m}\left(P_{bar} + \frac{\Delta H}{13.6}\right)\right]}{\theta V_s P_s A_n} \qquad \text{Equation 5-6}$$

where:

I = Percent of isokinetic sampling.

V_{l_c} = Total volume of liquid collected in impingers and silica gel (See Fig. 5-3), ml.

ρ_{H_2O} = Density of water, 1 g./ml.

R = Ideal gas constant, 21.83 inches Hg-cu. ft./lb.-mole-°R.

M_{H_2O} = Molecular weight of water, 18 lb./lb.-mole.

V_m = Volume of gas sample through the dry gas meter (meter conditions), cu. ft.

T_m = Absolute average dry gas meter temperature (see Figure 5-2), °R.

P_{bar} = Barometric pressure at sampling site, inches Hg.

ΔH = Average pressure drop across the orifice (see Fig. 5-2), inches H_2O.

T_s = Absolute average stack gas temperature (see Fig. 5-2), °R.

θ = Total sampling time, min.

V_s = Stack gas velocity calculated by Method 2, Equation 2-2, ft./sec.

P_s = Absolute stack gas pressure, inches Hg.

A_n = Cross-sectional area of nozzle, sq. ft.

6.8 Acceptable results. The following range sets the limit on acceptable isokinetic sampling results:

If $90\% \leq I \leq 110\%$, the results are acceptable, otherwise, reject the results and repeat the test.

7. *Reference.*

Addendum to Specifications for Incinerator Testing at Federal Facilities, PHS, NCAPC, Dec. 6, 1967.

Martin, Robert M., Construction Details of Isokinetic Source Sampling Equipment, Environmental Protection Agency, APTD-0581.

Rom, Jerome J., Maintenance, Calibration, and Operation of Isokinetic Source Sampling Equipment, Environmental Protection Agency, APTD-0576.

Smith, W. S., R. T. Shigehara, and W. F. Todd, A Method of Interpreting Stack Sampling Data, Paper presented at the 63d Annual Meeting of the Air Pollution Control Association, St. Louis, Mo., June 14-19, 1970.

Smith, W. S., et al., Stack Gas Sampling Improved and Simplified with New Equipment, APCA paper No. 67-119, 1967.

Specifications for Incinerator Testing at Federal Facilities, PHS, NCAPC, 1967.

METHOD 6—DETERMINATION OF SULFUR DIOXIDE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and applicability.*

1.1 Principle. A gas sample is extracted from the sampling point in the stack. The acid mist, including sulfur trioxide, is separated from the sulfur dioxide. The sulfur dioxide fraction is measured by the barium-thorin titration method.

1.2 Applicability. This method is applicable for the determination of sulfur dioxide emissions from stationary sources only when specified by the test procedures for determining compliance with New Source Performance Standards.

2. *Apparatus.*

2.1 Sampling. See Figure 6-1.

2.1.1 Probe—Pyrex[1] glass, approximately 5 to 6 mm. ID, with a heating system to prevent condensation and a filtering medium to remove particulate matter including sulfuric acid mist.

2.1.2 Midget bubbler—One, with glass wool packed in top to prevent sulfuric acid mist carryover.

2.1.3 Glass wool.

2.1.4 Midget impingers—Three.

2.1.5 Drying tube—Packed with 6 to 16 mesh indicating-type silica gel, or equivalent, to dry the sample.

2.1.6 Valve—Needle valve, or equivalent, to adjust flow rate.

2.1.7 Pump—Leak-free, vacuum type.

2.1.8 Rate meter—Rotameter or equivalent, to measure a 0-10 s.c.f.h. flow range.

2.1.9 Dry gas meter—Sufficiently accurate to measure the sample volume within 1%.

2.1.10 Pitot tube—Type S, or equivalent,

[1] Trade names.

necessary only if a sample traverse is required, or if stack gas velocity varies with time.

2.2 Sample recovery.

2.2.1 Glass wash bottles—Two.

2.2.2 Polyethylene storage bottles—To store impinger samples.

2.3 Analysis.

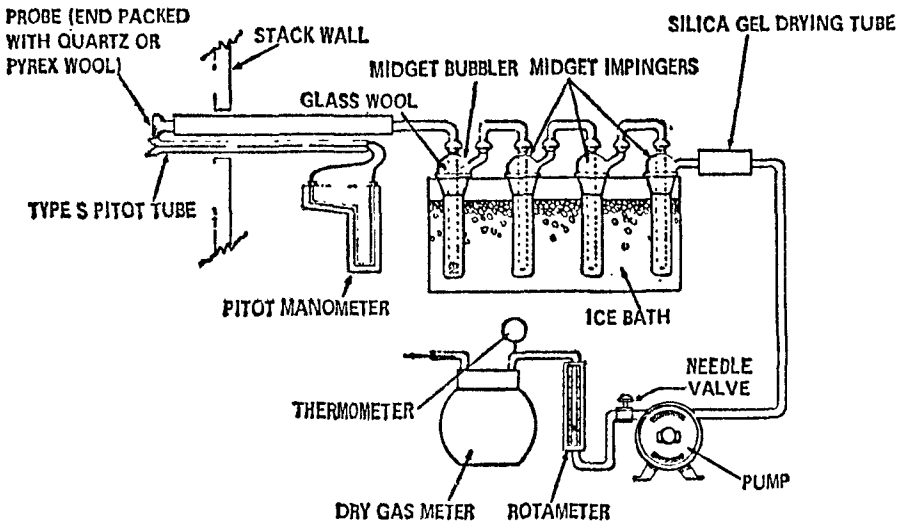


Figure 6-1. SO_2 sampling train.

2.3.1 Pipettes—Transfer type, 5 ml. and 10 ml. sizes (0.1 ml. divisions) and 25 ml. size (0.2 ml. divisions).

2.3.2 Volumetric flasks—50 ml., 100 ml., and 1,000 ml.

2.3.3 Burettes—5 ml. and 50 ml.

2.3.4 Erlenmeyer flask—125 ml.

3. *Reagents.*

3.1 Sampling.

3.1.1 Water—Deionized, distilled.

3.1.2 Isopropanol, 80%—Mix 80 ml. of isopropanol with 20 ml. of distilled water.

3.1.3 Hydrogen peroxide, 3%—dilute 100 ml. of 30% hydrogen peroxide to 1 liter with distilled water. Prepare fresh daily.

3.2 Sample recovery.

3.2.1 Water—Deionized, distilled.

3.2.2 Isopropanol, 80%.

3.3 Analysis.

3.3.1 Water—Deionized, distilled.

3.3.2 Isopropanol.

3.3.3 Thorin indicator—1-(o-arsonophenylazo)-2-naphthol-3,6-disulfonic acid, disodium salt (or equivalent). Dissolve 0.20 g. in 100 ml. distilled water.

3.3.4 Barium perchlorate (0.01 *N*)—Dissolve 1.95 g. of barium perchlorate [$Ba(ClO_4)_2 \cdot 3H_2O$] in 200 ml. distilled water and dilute to 1 liter with isopropanol. Standardize with sulfuric acid. Barium chloride may be used.

3.3.5 Sulfuric acid standard (0.01 *N*)—Purchase or standardize to ±0.0002 *N* against 0.01N NaOH which has previously been standardized against potassium acid phthalate (primary standard grade).

4. *Procedure.*

4.1 Sampling.

4.1.1 Preparation of collection train. Pour 15 ml. of 80% isopropanol into the midget bubbler and 15 ml. of 3% hydrogen peroxide into each of the first two midget impingers. Leave the final midget impinger dry. Assemble the train as shown in Figure 6-1. Leak check the sampling train at the sampling site by plugging the probe inlet and pulling a 10 inches Hg vacuum. A leakage rate not in excess of 1% of the sampling rate is acceptable. Carefully release the probe inlet plug and turn off the pump. Place crushed ice around the impingers. Add more ice during the run to keep the temperature of the gases leaving the last impinger at 70° F. or less.

4.1.2 Sample collection. Adjust the sample flow rate proportional to the stack gas velocity. Take readings at least every five minutes and when significant changes in stack conditions necessitate additional adjustments in flow rate. To begin sampling, position the tip of the probe at the first sampling point and start the pump. Sample proportionally throughout the run. At the conclusion of each run, turn off the pump and record the final readings. Remove the probe from the stack and disconnect it from the train. Drain the ice bath and purge the remaining part of the train by drawing clean ambient air through the system for 15 minutes.

4.2 Sample recovery. Disconnect the impingers after purging. Discard the contents of the midget bubbler. Pour the contents of the midget impingers into a polyethylene shipment bottle. Rinse the three midget impingers and the connecting tubes with distilled water and add these washings to the same storage container.

4.3 Sample analysis. Transfer the contents of the storage container to a 50 ml. volumetric flask. Dilute to the mark with deionized, distilled water. Pipette a 10 ml. aliquot of this solution into a 125 ml. Erlenmeyer flask. Add 40 ml. of isopropanol and two to four drops of thorin indicator. Titrate to a pink endpoint using 0.01 *N* barium perchlorate. Run a blank with each series of samples.

5. *Calibration.*

5.1 Use standard methods and equipment which have been approved by the Administrator to calibrate the rotameter, pitot tube, dry gas meter, and probe heater.

5.2 Standardize the barium perchlorate against 25 ml. of standard sulfuric acid containing 100 ml. of isopropanol.

6. *Calculations.*

6.1 Dry gas volume. Correct the sample volume measured by the dry gas meter to standard conditions (70° F. and 29.92 inches Hg) by using equation 6-1.

$$V_{m_{std}} = V_m \left(\frac{T_{std}}{T_m}\right)\left(\frac{P_{bar}}{P_{std}}\right) = 17.71 \frac{^\circ R}{\text{in. Hg}} \left(\frac{V_m P_{bar}}{T_m}\right) \quad \text{equation 6-1}$$

where:

$V_{m_{std}}$ = Volume of gas sample through the dry gas meter (standard conditions), cu. ft.

V_m = Volume of gas sample through the dry gas meter (meter conditions), cu. ft.

T_{std} = Absolute temperature at standard conditions, 530° R.

T_m = Average dry gas meter temperature, °R.

P_{bar} = Barometric pressure at the orifice meter, inches Hg.

P_{std} = Absolute pressure at standard conditions, 29.92 inches Hg.

6.2 Sulfur dioxide concentration.

$$C_{SO_2} = \left(7.05 \times 10^{-5} \frac{\text{lb.-l.}}{\text{g.-ml.}}\right) \frac{(V_t - V_{tb}) N \left(\frac{V_{soln}}{V_a}\right)}{V_{m_{std}}} \quad \text{equation 6-2}$$

where:

C_{SO_2} = Concentration of sulfur dioxide at standard conditions, dry basis, lb./cu. ft.

7.05×10^{-5} = Conversion factor, including the number of grams per gram equivalent of sulfur dioxide (32 g./g.-eq.), 453.6 g./lb., and 1,000 ml./l., lb.-l./g.-ml.

V_t = Volume of barium perchlorate titrant used for the sample, ml.

V_{tb} = Volume of barium perchlorate titrant used for the blank, ml.

N = Normality of barium perchlorate titrant, g.-eq./l.

V_{soln} = Total solution volume of sulfur dioxide, 50 ml.

V_a = Volume of sample aliquot titrated, ml.

$V_{m_{std}}$ = Volume of gas sample through the dry gas meter (standard conditions), cu. ft., see Equation 6-1.

7. *References.*

Atmospheric Emissions from Sulfuric Acid Manufacturing Processes, U.S. DHEW, PHS, Division of Air Pollution, Public Health Service Publication No. 999-AP-13, Cincinnati, Ohio, 1965.

Corbett, P. F., The Determination of SO_2 and SO_3 in Flue Gases, Journal of the Institute of Fuel, 24:237-243, 1961.

Matty, R. E. and E. K. Diehl, Measuring Flue-Gas SO_2 and SO_3, Power *101*:94-97, November, 1957.

Patton, W. F. and J. A. Brink, Jr., New Equipment and Techniques for Sampling Chemical Process Gases, J. Air Pollution Control Association, *13*, 162 (1963).

METHOD 7—DETERMINATION OF NITROGEN OXIDE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and applicability.*

1.1 Principle. A grab sample is collected in an evacuated flask containing a dilute sulfuric acid-hydrogen peroxide absorbing solution, and the nitrogen oxides, except

nitrous oxide, are measure colorimetrically using the phenoldisulfonic acid (PDS) procedure.

1.2 Applicability. This method is applicable for the measurement of nitrogen oxides from stationary sources only when specified by the test procedures for determining compliance with New Source Performance Standards.

2. *Apparatus.*

2 1 Sampling. See Figure 7-1.

2.1.1 Probe—Pyrex[1] glass, heated, with filter to remove particulate matter. Heating is unnecessary if the probe remains dry during the purging period.

2.1 2 Collection flask—Two-liter, Pyrex,[1] round bottom with short neck and 24/40 standard taper opening, protected against implosion or breakage.

[1] Trade name.

2.1.3 Flask valve—T-bore stopcock connected to a 24/40 standard taper joint.

2.1.4 Temperature gauge—Dial-type thermometer, or equivalent, capable of measuring 2° F. intervals from 25° to 125° F.

2.1.5 Vacuum line—Tubing capable of withstanding a vacuum of 3 inches Hg absolute pressure, with "T" connection and T-bore stopcock, or equivalent.

2.1.6 Pressure gauge—U-tube manometer, 36 inches, with 0.1-inch divisions, or equivalent.

2 1.7 Pump—Capable of producing a vacuum of 3 inches Hg absolute pressure.

2.1.8 Squeeze bulb—One way.

2.2 Sample recovery.

2.2.1 Pipette or dropper.

2.2.2 Glass storage containers—Cushioned for shipping.

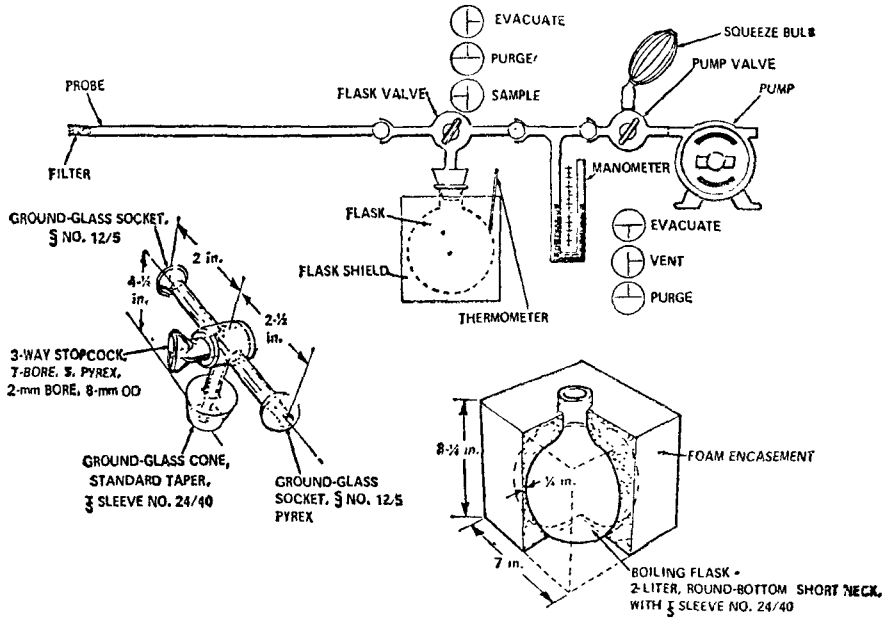


Figure 7-1. Sampling train, flask valve, and flask.

2.2.3 Glass wash bottle.

2.3 Analysis.

2.3.1 Steam bath.

2.3.2 Beakers or casseroles—250 ml., one for each sample and standard (blank).

2.3.3 Volumetric pipettes—1, 2, and 10 ml.

2.3.4 Transfer pipette—10 ml. with 0.1 ml. divisions.

2.3.5 Volumetric flask—100 ml., one for each sample, and 1,000 ml. for the standard (blank).

2.3.6 Spectrophotometer—To measure absorbance at 420 nm.

2.3.7 Graduated cylinder—100 ml. with 1.0 ml. divisions.

2 3.8 Analytical balance—To measure to 0.1 mg.

3. *Reagents.*

3.1 Sampling.

3.1.1 Absorbing solution—Add 2.8 ml. of concentrated H_2SO_4 to 1 liter of distilled water. Mix well and add 6 ml. of 3 percent hydrogen peroxide. Prepare a fresh solution weekly and do not expose to extreme heat or direct sunlight.

3.2 Sample recovery.

3.2.1 Sodium hydroxide (1*N*)—Dissolve 40 g. NaOH in distilled water and dilute to 1 liter.

3 2 2 Red litmus paper.

3.2.3 Water—Deionized, distilled.

3.3 Analysis.

3 3.1 Fuming sulfuric acid—15 to 18% by weight free sulfur trioxide.

3.3.2 Phenol—White solid reagent grade.

3.3.3 Sulfuric acid—Concentrated reagent grade.

3.3.4 Standard solution—Dissolve 0.5495 g. potassium nitrate (KNO_3) in distilled water and dilute to 1 liter. For the working standard solution, dilute 10 ml. of the resulting solution to 100 ml. with distilled water. One ml. of the working standard solution is equivalent to 25 μg. nitrogen dioxide.

3.3.5 Water—Deionized, distilled.

3.3.6 Phenoldisulfonic acid solution—Dissolve 25 g. of pure white phenol in 150 ml. concentrated sulfuric acid on a steam bath. Cool, add 75 ml. fuming sulfuric acid, and heat at 100° C. for 2 hours. Store in a dark, stoppered bottle.

4. *Procedure.*

4.1 Sampling.

4.1.1 Pipette 25 ml. of absorbing solution into a sample flask. Insert the flask valve stopper into the flask with the valve in the "purge" position. Assemble the sampling train as shown in Figure 7-1 and place the probe at the sampling point. Turn the flask valve and the pump valve to their "evacuate" positions. Evacuate the flask to at least 3 inches Hg absolute pressure. Turn the pump valve to its "vent" position and turn off the pump. Check the manometer for any fluctuation in the mercury level. If there is a visible change over the span of one minute, check for leaks. Record the initial volume, temperature, and barometric pressure. Turn the flask valve to its "purge" position, and then do the same with the pump valve. Purge the probe and the vacuum tube using the squeeze bulb. If condensation occurs in the probe and flask valve area, heat the probe and purge until the condensation disappears. Then turn the pump valve to its "vent" position. Turn the flask valve to its "sample" position and allow sample to enter the flask for about 15 seconds. After collecting the sample, turn the flask valve to its "purge" position and disconnect the flask from the sampling train. Shake the flask for 5 minutes.

4.2 Sample recovery.

4.2.1 Let the flask set for a minimum of 16 hours and then shake the contents for 2 minutes. Connect the flask to a mercury filled U-tube manometer, open the valve from the flask to the manometer, and record the flask pressure and temperature along with the barometric pressure. Transfer the flask contents to a container for shipment or to a 250 ml. beaker for analysis. Rinse the flask with two portions of distilled water (approximately 10 ml.) and add rinse water to the sample. For a blank use 25 ml. of absorbing solution and the same volume of distilled water as used in rinsing the flask. Prior to shipping or analysis, add sodium hydroxide (1*N*) dropwise into both the sample and the blank until alkaline to litmus paper (about 25 to 35 drops in each).

4.3 Analysis.

4.3.1 If the sample has been shipped in a container, transfer the contents to a 250 ml. beaker using a small amount of distilled water. Evaporate the solution to dryness on a steam bath and then cool. Add 2 ml. phenoldisulfonic acid solution to the dried residue and triturate thoroughly with a glass rod. Make sure the solution contacts all the residue. Add 1 ml. distilled water and four drops of concentrated sulfuric acid. Heat the solution on a steam bath for 3 minutes with occasional stirring. Cool, add 20 ml. distilled water, mix well by stirring, and add concentrated ammonium hydroxide dropwise with constant stirring until alkaline to litmus paper. Transfer the solution to a 100 ml. volumetric flask and wash the beaker three times with 4 to 5 ml. portions of distilled water. Dilute to the mark and mix thoroughly. If the sample contains solids, transfer a portion of the solution to a clean, dry centrifuge tube, and centrifuge, or filter a portion of the solution. Measure the absorbance of each sample at 420 nm. using the blank solution as a zero. Dilute the sample and the blank with a suitable amount of distilled water if absorbance falls outside the range of calibration.

5. *Calibration.*

5.1 Flask volume. Assemble the flask and flask valve and fill with water to the stopcock. Measure the volume of water to ±10 ml. Number and record the volume on the flask.

5.2 Spectrophotometer. Add 0.0 to 16.0 ml. of standard solution to a series of beakers. To each beaker add 25 ml. of absorbing solution and add sodium hydroxide (1*N*) dropwise until alkaline to litmus paper (about 25 to 35 drops). Follow the analysis procedure of section 4.3 to collect enough data to draw a calibration curve of concentration in μg. NO_2 per sample versus absorbance.

6. *Calculations.*

6.1 Sample volume.

$$V_{sc}=\frac{T_{std}(V_f-V_a)}{P_{std}}\left(\frac{P_f}{T_f}-\frac{P_i}{T_i}\right)=\left(17.71\ \frac{°R}{in.\ H_g}\right)(V_f-25\ ml.)\left(\frac{P_f}{T_f}-\frac{P_i}{T_i}\right)\quad \text{Equation 7-1}$$

where:

V_{sc} = Sample volume at standard conditions (dry basis), ml.

T_{std} = Absolute temperature at standard conditions, 530° R.

P_{std} = Pressure at standard conditions, 29.92 inches Hg.

V_f = Volume of flask and valve, ml.

V_a = Volume of absorbing solution, 25 ml.

P_f = Final absolute pressure of flask, inches Hg.

P_i = Initial absolute pressure of flask, inches Hg.

T_f = Final absolute temperature of flask, °R.

T_i = Initial absolute temperature of flask, °R.

6.2 Sample concentration. Read $\mu g.\ NO_2$ for each sample from the plot of $\mu g.\ NO_2$ versus absorbance.

$$C=\left(\frac{m}{V_{sc}}\right)\left(\frac{1\ lb.}{cu.\ ft.}\right)=\left(6.2\times10^{-5}\frac{lb./s.c.f.}{\mu g./ml.}\right)\left(\frac{m}{V_{sc}}\right)$$

equation 7-2

where:

C = Concentration of NO_x as NO_2 (dry basis), lb./s.c.f.

m = Mass of NO_2 in gas sample, $\mu g.$

V_{sc} = Sample volume at standard conditions (dry basis), ml.

7. *References.*

Standard Methods of Chemical Analysis. 6th ed. New York, D. Van Nostrand Co., Inc., 1962, vol. 1, p. 329–330.

Standard Method of Test for Oxides of Nitrogen in Gaseous Combustion Products (Phenoldisulfonic Acid Procedure), In: 1968 Book of ASTM Standards, Part 23, Philadelphia, Pa. 1968, ASTM Designation D–1608–60, p. 725–729.

Jacob, M. B., The Chemical Analysis of Air Pollutants, New York, N.Y., Interscience Publishers, Inc., 1960, vol. 10, p. 351–356.

METHOD 8—DETERMINATION OF SULFURIC ACID MIST AND SULFUR DIOXIDE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and applicability.*

1.1 Principle. A gas sample is extracted from a sampling point in the stack and the acid mist including sulfur trioxide is separated from sulfur dioxide. Both fractions are measured separately by the barium-thorin titration method.

1.2 Applicability. This method is applicable to determination of sulfuric acid mist (including sulfur trioxide) and sulfur dioxide from stationary sources only when specified by the test procedures for determining compliance with the New Source Performance Standards.

2. *Apparatus.*

2.1 Sampling. See Figure 8–1. Many of the design specifications of this sampling train are described in APTD–0581.

2.1.1 Nozzle—Stainless steel (316) with sharp, tapered leading edge.

2.1.2 Probe—Pyrex[1] glass with a heating system to prevent visible condensation during sampling.

2.1.3 Pitot tube—Type S, or equivalent, attached to probe to monitor stack gas velocity.

2.1.4 Filter holder—Pyrex[1] glass.

2.1.5 Impingers—Four as shown in Figure 8–1. The first and third are of the Greenburg-Smith design with standard tip. The second and fourth are of the Greenburg-Smith design, modified by replacing the standard tip with a ½-inch ID glass tube extending to one-half inch from the bottom of the impinger flask. Similar collection systems, which have been approved by the Administrator, may be used.

2.1.6 Metering system—Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 5° F., dry gas meter with 2% accuracy, and related equipment, or equivalent, as required to maintain an isokinetic sampling rate and to determine sample volume.

2.1.7 Barometer—To measure atmospheric pressure to ±0.1 inch Hg.

[1] Trade name.

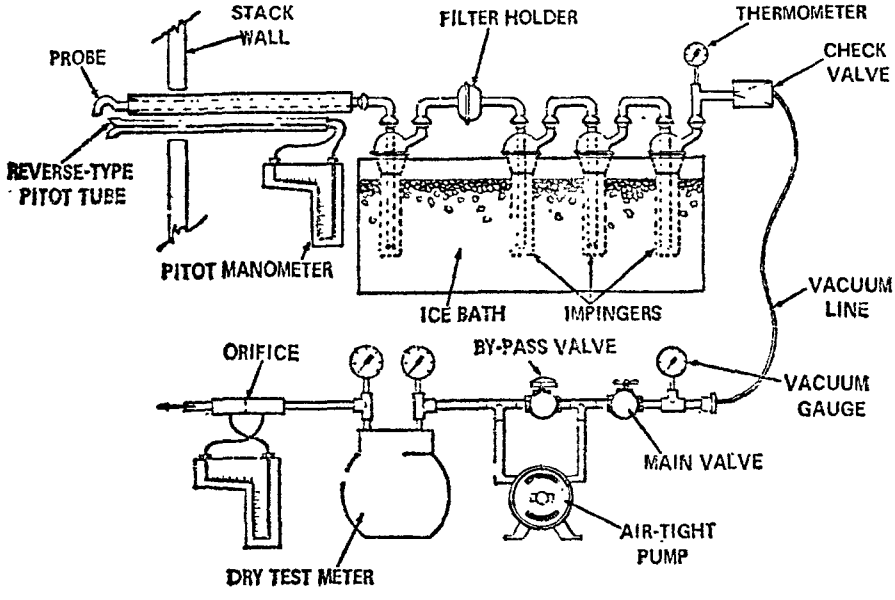


Figure 8-1. Sulfuric acid mist sampling train.

2.2 Sample recovery.

2.2.1 Wash bottles—Two.

2.2.2 Graduated cylinders—250 ml., 500 ml.

2.2.3 Glass sample storage containers.

2.2.4 Graduated cylinder—250 ml.

2.3 Analysis.

2.3.1 Pipette—25 ml., 100 ml.

2.3.2 Burette—50 ml.

2.3.3 Erlenmeyer flask—250 ml.

2.3.4 Graduated cylinder—100 ml.

2.3.5 Trip balance—300 g. capacity, to measure to ±0.05 g.

2.3.6 Dropping bottle—to add indicator solution.

3. *Reagents.*

3.1 Sampling.

3.1.1 Filters—Glass fiber, MSA type 1106 BH, or equivalent, of a suitable size to fit in the filter holder.

3.1.2 Silica gel—Indicating type, 6–16 mesh, dried at 175° C. (350° F.) for 2 hours.

3.1.3 Water—Deionized, distilled.

3.1.4 Isopropanol, 80%—Mix 800 ml. of isopropanol with 200 ml. of deionized, distilled water.

3.1.5 Hydrogen peroxide, 3%—Dilute 100 ml. of 30% hydrogen peroxide to 1 liter with deionized, distilled water.

3.1.6 Crushed ice.

3.2 Sample recovery.

3.2.1 Water—Deionized, distilled.

3.2.2 Isopropanol, 80%.

3.3 Analysis.

3.3.1 Water—Deionized, distilled.

3.3.2 Isopropanol.

3.3.3 Thorin indicator—1-(o-arsonophenylazo)-2-naphthol-3, 6-disulfonic acid, disodium salt (or equivalent). Dissolve 0.20 g. in 100 ml. distilled water.

3.3.4 Barium perchlorate (0.01*N*)—Dissolve 1.95 g. of barium perchlorate [$Ba(ClO_4)_2 \cdot 3\ H_2O$] in 200 ml. distilled water and dilute to 1 liter with isopropanol. Standardize with sulfuric acid.

3.3.5 Sulfuric acid standard (0.01*N*)—Purchase or standardize to ± 0.0002 *N* against 0.01 *N* NaOH which has previously been standardized against primary standard potassium acid phthalate.

4. *Procedure.*

4.1 Sampling.

4.1.1 After selecting the sampling site and the minimum number of sampling points, determine the stack pressure, temperature, moisture, and range of velocity head.

4.1.2 Preparation of collection train. Place 100 ml. of 80% isopropanol in the first impinger, 100 ml. of 3% hydrogen peroxide in both the second and third impingers, and about 200 g. of silica gel in the fourth impinger. Retain a portion of the reagents for use as blank solutions. Assemble the train without the probe as shown in Figure 8–1 with the filter between the first and second impingers. Leak check the sampling train at the sampling site by plugging the inlet to the first impinger and pulling a 15-inch Hg vacuum. A leakage rate not in excess of 0.02 c.f.m. at a vacuum of 15 inches Hg is acceptable. Attach the probe and turn on the probe heating system. Adjust the probe heater setting during sampling to prevent any visible condensation. Place crushed ice around the impingers. Add more ice during the run to keep the temperature of the gases leaving the last impinger at 70° F. or less.

4.1.3 Train operation. For each run, record the data required on the example sheet shown in Figure 8–2. Take readings at each sampling point at least every 5 minutes and when significant changes in stack conditions necessitate additional adjustments in flow rate. To begin sampling, position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Start the pump and immediately adjust the flow to isokinetic conditions. Maintain isokinetic sampling throughout the sampling period. Nomographs are available which aid in the

rapid adjustment of the sampling rate without other computations. APTD–0576 details the procedure for using these nomographs. At the conclusion of each run, turn off the pump and record the final readings. Remove the probe from the stack and disconnect it from the train. Drain the ice bath and purge the remaining part of the train by drawing clean ambient air through the system for 15 minutes.

PLANT_____ AMBIENT TEMPERATURE_____

LOCATION_____ BAROMETRIC PRESSURE_____

OPERATOR_____ ASSUMED MOISTURE, %_____

DATE_____ HEATER BOX SETTING_____

RUN NO._____ PROBE LENGTH, m._____

SAMPLE BOX NO._____ NOZZLE DIAMETER, in._____

METER BOX NO._____ PROBE HEATER SETTING_____

METER $\Delta H_@$_____

C FACTOR_____

SCHEMATIC OF STACK CROSS SECTION

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	STATIC PRESSURE (P_g), in. Hg.	STACK TEMPERATURE (T_s), °F	VELOCITY HEAD (ΔP_g),	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER (ΔH), in. H_2O	GAS SAMPLE VOLUME (Vm), ft^3	GAS SAMPLE TEMPERATURE AT DRY GAS METER		SAMPLE BOX TEMPERATURE, °F	IMPINGER TEMPERATURE, °F
							INLET ($T_{m_{in}}$), °F	OUTLET ($T_{m_{out}}$), °F		
TOTAL							Avg.	Avg.		
AVERAGE							Avg.			

Figure 8-2. Field data.

4.2 Sample recovery.

4.2.1 Transfer the isopropanol from the first impinger to a 250 ml. graduated cylinder. Rinse the probe, first impinger, and all connecting glassware before the filter with 80% isopropanol. Add the rinse solution to the cylinder. Dilute to 250 ml. with 80% isopropanol. Add the filter to the solution, mix, and transfer to a suitable storage container. Transfer the solution from the second and third impingers to a 500 ml. graduated cylinder. Rinse all glassware between the filter and silica gel impinger with deionized, distilled water and add this rinse water to the cylinder. Dilute to a volume of 500 ml. with deionized, distilled water. Transfer the solution to a suitable storage container.

4.3 Analysis.

4.3.1 Shake the container holding isopropanol and the filter. If the filter breaks up, allow the fragments to settle for a few minutes before removing a sample. Pipette a 100 ml. aliquot of sample into a 250 ml. Erlenmeyer flask and add 2 to 4 drops of thorin indicator. Titrate the sample with barium perchlorate to a pink end point. Make sure to record volumes. Repeat the titration with a second aliquot of sample. Shake the container holding the contents of the second and third impingers. Pipette a 25 ml. aliquot of sample into a 250 ml. Erlenmeyer flask. Add 100 ml. of isopropanol and 2 to 4 drops of thorin indicator. Titrate the sample with barium perchlorate to a pink end point. Repeat the titration with a second aliquot of sample. Titrate the blanks in the same manner as the samples.

5. *Calibration.*

5.1 Use standard methods and equipment which have been approved by the Administrator to calibrate the orifice meter, pitot tube, dry gas meter, and probe heater.

5.2 Standardize the barium perchlorate with 25 ml. of standard sulfuric acid containing 100 ml. of isopropanol.

6. *Calculations.*

6.1 Dry gas volume. Correct the sample volume measured by the dry gas meter to standard conditions (70° F., 29.92 inches Hg) by using Equation 8–1.

$$V_{m_{std}} = V_m\left(\frac{T_{std}}{T_m}\right)\left(\frac{P_{bar}+\frac{\Delta H}{13.6}}{P_{std}}\right) = \left(17.71\frac{°R}{\text{in. Hg}}\right)V_m\left(\frac{P_{bar}+\frac{\Delta H}{13.6}}{T_m}\right) \qquad \text{equation 8–1}$$

where:

$V_{m_{std}}$ = Volume of gas sample through the dry gas meter (standard conditions), cu. ft.

V_m = Volume of gas sample through the dry gas meter (meter conditions), cu. ft.

T_{std} = Absolute temperature at standard conditions, 530° R.

T_m = Average dry gas meter temperature, °R.

P_{bar} = Barometric pressure at the orifice meter, inches Hg.

ΔH = Pressure drop across the orifice meter, inches H_2O.

13.6 = Specific gravity of mercury.

P_{std} = Absolute pressure at standard conditions, 29.92 inches Hg.

6.2 Sulfuric acid concentration.

$$C_{H_2SO_4} = \left(1.08\times10^{-4}\frac{\text{lb.-l.}}{\text{g.-ml.}}\right)\frac{(V_t - V_{tb})(N)\left(\frac{V_{soln}}{V_a}\right)}{V_{m_{std}}} \qquad \text{equation 8–2}$$

$C_{H_2SO_4}$ = Concentration of sulfuric acid at standard conditions, dry basis, lb./cu. ft.

1.08×10^{-4} = Conversion factor including the number of grams per gram equivalent of sulfuric acid (49 g./g.-eq.), 453.6 g./lb., and 1,000 ml./l., lb.-l./g.-ml.

V_t = Volume of barium perchlorate titrant used for the sample, ml.

V_{tb} = Volume of barium perchlorate titrant used for the blank, ml.

N = Normality of barium perchlorate titrant, g.-eq./l.

V_{soln} = Total solution volume of sulfuric acid (first impinger and filter), ml.

V_a = Volume of sample aliquot titrated, ml.

$V_{m_{std}}$ = Volume of gas sample through the dry gas meter (standard conditions), cu. ft., see Equation 8–1.

6.3 Sulfur dioxide concentration.

$$C_{SO_2} = \left(7.05\times10^{-5}\frac{\text{lb.-l.}}{\text{g.-ml.}}\right)\frac{(V_t - V_{tb})(N)\left(\frac{V_{soln}}{V_a}\right)}{V_{m_{std}}} \qquad \text{equation 8–3}$$

where:

C_{SO_2} = Concentration of sulfur dioxide at standard conditions, dry basis, lb./cu. ft.

7.05×10^{-5} = Conversion factor including the number of grams per gram equivalent of sulfur dioxide (32 g./g.-eq.) 453.6 g./lb., and 1,000 ml./l., lb.-l./g.-ml.

V_t = Volume of barium perchlorate titrant used for the sample, ml.

V_{tb} = Volume of barium perchlorate titrant used for the blank, ml.

N = Normality of barium perchlorate titrant, g.-eq./l.

V_{soln} = Total solution volume of sulfur dioxide (second and third impingers), ml.

V = Volume of sample aliquot titrated, ml.

$V_{m_{std}}$ = Volume of gas sample through the dry gas meter (standard conditions), cu. ft., see Equation 8–1.

7. *References.*

Atmospheric Emissions from Sulfuric Acid Manufacturing Processes, U.S. DHEW, PHS, Division of Air Pollution, Public Health Service Publication No. 999–AP–13, Cincinnati, Ohio, 1965.

Corbett, D. F., The Determination of SO_2 and SO_3 in Flue Gases, Journal of the Institute of Fuel, 24:237–243, 1961.

Martin, Robert M., Construction Details of Isokinetic Source Sampling Equipment, Environmental Protection Agency, Air Pollution Control Office Publication No. APTD–0581.

Patton, W. F., and J. A. Brink, Jr., New Equipment and Techniques for Sampling Chemical Process Gases, J. Air Pollution Control Assoc. *13*, 162 (1963).

Rom, Jerome J., Maintenance, Calibration, and Operation of Isokinetic Source Sampling Equipment, Environmental Protection Agency, Air Pollution Control Office Publication No. APTD–0576.

Shell Development Co. Analytical Department, Determination of Sulfur Dioxide and Sulfur Trioxide in Stack Gases, Emeryville Method Series, 4516/59a.

METHOD 9—VISUAL DETERMINATION OF THE OPACITY OF EMISSIONS FROM STATIONARY SOURCES

1. *Principle and applicability.*

1.1 Principle. The relative opacity of an emission from a stationary source is determined visually by a qualified observer.

1.2 Applicability. This method is applicable for the determination of the relative opacity of visible emissions from stationary sources only when specified by test procedures for determining compliance with the New Source Performance Standards.

2. *Procedure.*

2.1 The qualified observer stands at approximately two stack heights, but not more than a quarter of a mile from the base of the stack with the sun to his back. From a vantage point perpendicular to the plume, the observer studies the point of greatest opacity in the plume. The data required in Figure 9–1 is recorded every 15 to 30 seconds to the nearest 5% opacity. A minimum of 25 readings is taken.

3. *Qualifications.*

3.1 To certify as an observer, a candidate must complete a smokereading course conducted by EPA, or equivalent; in order to certify the candidate must assign opacity readings in 5% increments to 25 different black plumes and 25 different white plumes, with an error not to exceed 15 percent on any one reading and an average error not to exceed 7.5 percent in each category. The smoke generator used to qualify the observers must be equipped with a calibrated smoke indicator or light transmission meter located in the source stack if the smoke generator is to determine the actual opacity of the emissions. All qualified observers must pass this test every 6 months in order to remain certified.

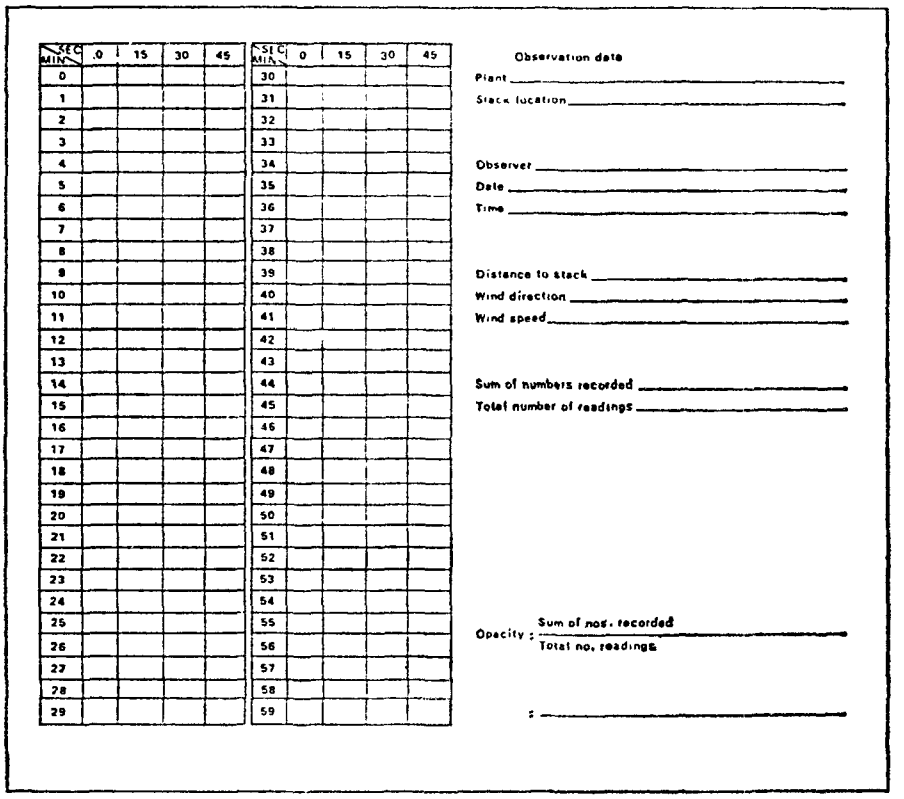
4. *Calculations.*

4.1 Determine the average opacity.

5. *References.*

Air Pollution Control District Rules and Regulations, Los Angeles County Air Pollution Control District, Chapter 2, Schedule 6, Regulation 4, Prohibition, Rule 50, 17 p.

Kudluk, Rudolf, Ringelmann Smoke Chart, U.S. Department of Interior, Bureau of Mines, Information Circular No. 8333, May 1967.



SEC / MIN	0	15	30	45
0				
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				

SEC / MIN	0	15	30	45
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50				
51				
52				
53				
54				
55				
56				
57				
58				
59				

Observation date

Plant _____

Stack location _____

Observer _____

Date _____

Time _____

Distance to stack _____

Wind direction _____

Wind speed _____

Sum of numbers recorded _____

Total number of readings _____

Opacity : $\frac{\text{Sum of nos. recorded}}{\text{Total no. readings}}$ = _____

Figure 9-1. Field data.

[FR Doc.71-18624 Filed 12-22-71;8:45 am]

1A

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Supplemental Statement in Connection With Final Promulgation

I. EPA published Standards of Performance for New Stationary Sources in final form, prefaced by a "concise general statement of their basis and purpose" as required by section 4(c) of the Administrative Procedure Act, 5 U.S.C. 553(c), on December 23, 1971. 36 F.R. 24876. Petitions for review of certain of these standards were filed on January 21 and 24 by the Essex Chemical Corp. et al., the Portland Cement Association, and the Appalachian Power Co. et al. (U.S. Court of Appeals for the District of Columbia, Nos. 72-1072, 72-1073, and 72-1079).

On February 18, 1972, almost 2 months after EPA published the New Stationary Source Standards, the U.S. Court of Appeals for the District of Columbia Circuit handed down its decision in "Kennecott Copper Corp. v. Environmental Protection Agency" (C.A.D.C. No. 71-1410), which concerned a national secondary ambient air quality standard promulgated by EPA pursuant to section 109(b) of the Clean Air Amendments of 1970, 42 U.S.C. 1857C-4(b). The court there held that although the "concise general statement" prefacing the standard involved satisfied the requirements of section 4(c) of the Administrative Procedure Act, it would nonetheless remand the cause to the Administrator for a more specific explanation of how he had arrived at the standard.

In light of the decision in "Kennecott Copper," and in the interest of a speedy judicial determination of the validity of the Standards of Performance for New Stationary Sources, we have prepared this statement of the basis of the Administrator's decision to promulgate the standards to supplement that appearing as the preface to the final standards as published in December 1971. Although if the point were raised it might ultimately be determined that this statement was not necessary to satisfy the doctrine expressed by the "Kennecott Copper" opinion, EPA considers it fundamental to the national policy embodied in the Clean Air Amendments of 1970 to expedite all steps of promulgation and enforcement of standards and implementation plans to bring about clean air. The speedy eradication of any uncertainty as to the validity of the standards for new stationary sources is an important part of this process. Accordingly, considering the particular sequence of events and pressures of time involved here, we think it most appropriate to include this supplementary statement in the record now, thereby ensuring the rapid conclusion of judicial review of the validity of the standards.

II. 1. *The Particulate Test Method.* Particulate emission limits were proposed for steam generators, incinerators, and cement plants, based on measurements made with the full EPA sampling train, which includes a dry filter as well as impingers, which contain water and act as condensers and scrubbers. In the impingers the gases are cooled to about 70° F. before metering.

There were objections to the use of impingers in the EPA sampling train, with suggestions that the particulate standards be based either on the "front half" (probe and filter) of the EPA sampling train or on the American Society of Mechanical Engineers test procedure. Both of these methods measure only those materials that are solids or liquids at 250° F. and greater temperatures.

It is the opinion of EPA engineers that particulate standards based either on the front half or the full EPA sampling train will require the same degree of control if appropriate limits are applied. Analyses by EPA show that the material collected in the impingers of the sampling train is usually although not in every case a consistent fraction of the total particulate loading. Nevertheless, there is some question that all of the material collected in the impingers would truly form particulates in the atmosphere under normal dispersion conditions. For instance, gaseous sulfur dioxide may be oxidized to a particulate form—sulfur trioxide and sulfuric acid—in the sampling train. Much of the material found in the impingers is sulfuric acid and sulfates. There has been only limited sampling with the full EPA train such that the occasional anomalies cannot be explained fully at this time. In any case, the front half of the EPA train is considered a more acceptable means of measuring filterable particulates than the ASME method in that a more efficient filter is required and the filter has far less mass than the principal ASME filter in relation to the sample collected. The latter position was reinforced by a recommendation of the Air Pollution Control Association.

Accordingly, we determined that, for the three affected source categories, steam generators, incinerators, and cement plants, particulate standards should be based on the front half of the EPA sampling train with mass emission limits adjusted as follows:

	Originally proposed particulate standards, full EPA train	Recommended particulate standards revised sample method (front half only)
Steam Generators—pounds per million Btu heat input	0.20	0.10
Incinerators—grains per standard cubic foot at 12 percent CO_2	0.10	0.08
Cement Kilns—pounds per ton feed	0.30	0.30
Cement Coolers—pounds per ton feed	0.10	0.10

The adjusted standards are based on EPA sampling results and are designed to provide the same degree of control as the originally proposed standards. In the case of steam generators, the installations which were found to be best controlled showed reasonably large concentrations (about 50 percent) of materials in the impingers. The five incinerator

tests which showed compliance with the originally proposed standard all indicated impinger catches of 20 to 30 percent. All five of these tests indicate compliance with the original and the revised standard.

In the case of cement plants, holding to the same allowable emission rate while changing the sampling method results in a slight relaxation of the standard. This permits an electrostatic precipitator as well as a fabric filter to meet the emission standard.

2. *The Sulfur Dioxide Standard for Steam Generators of 1.2 Pounds Per Million B.T.U. Heat Input.* The Administrator took into account the following facts in determining that there has been adequate demonstration of the achievability of the standard.

There are at present three SO_2 removal systems in operation at U.S. power stations. Moreover, a total of 13 electric power companies have contracted for the construction of seventeen additional units, most of which will become operational in the next 2 years. Most of these employ lime or limestone scrubbing, but magnesium oxide and sodium hydroxide scrubbing and catalytic oxidation also will be used. In addition, seven units will be equipped with water scrubbers for fly ash collection in the anticipation that they may be converted to SO_2 removal in the future. Eight different firms are designing the installations. One of the installations, a sodium hydroxide scrubber, is guaranteed by the designer to achieve 90 percent or better SO_2 removal. Four others are guaranteed at 80 percent or better. Table I summarizes information about these installations. Generally, the standard of 1.2 pounds of sulfur dioxide per million B.t.u. input can be met by the removal of 70–75 percent of the sulfur dioxide formed in the burning of coal of average sulfur content (i.e., 2.8–3 percent).

A 125-megawatt unit now operated by the Kansas Power and Light Co. at Lawrence, Kans., was put into operation in December 1968. Several problems were experienced originally and appreciable revisions have been made to improve the system. The most successful operation of the scrubber has occurred during 1971.

In some respects the plant is atypical in that it is not required to burn coal continually. Natural gas is available much of the time, and the station also has a supply of fuel oil that can be burned in emergencies when natural gas is not available. Kansas Power and Light has used this flexibility to advantage in the operation of the scrubber. It frequently switches the unit from coal to natural gas, bypassing the scrubber, so that they can inspect the internals for possible malfunction. The generating unit was seldom operated longer than 4 weeks on coal firing without making such inspections. In most instances, little or no maintenance was required during the outage, and the company then merely inspected the scrubber.

TABLE I—SULFUR DIOXIDE REMOVAL SYSTEMS AT U.S. STEAM-ELECTRIC PLANTS

Power station	Unit size	Designer SO_2 system	New or retrofit	Scheduled startup	Anticipated efficiency of SO_2 removal
Limestone Scrubbing:	*MW*				
1. Union Electric Co., Meramec No. 2.	140	Combustion Engineer.	R	September 1968	Operated at 73% efficiency during EPA test.
2. Kansas Power & Light, Lawrence Station No. 4.	125	Combustion Engineer.	R	December 1968	Do.
3. Kansas Power & Light, Lawrence Station No. 5.	430	Combustion Engineer.	N	December 1971	Will start at 65% and be upgraded to 83%
4. Kansas City Power & Light, Hawthorne Station No. 3.	100	Combustion Engineer.	R	Late 1972	Guaranteed 70%.
5. Kansas City Power & Light, Hawthorne, Station No. 4.	100	Combustion Engineer.	R	Late 1972	Do.
6. Kansas City Power & Light, Lacygne Station.	800	Babcock & Wilcox	N	Late 1972	80% as target.
7. Detroit Edison Co., St. Clair Station No. 3.	180	Peabody	R	Late 1972	90% as target.
8. Detroit Edison Co., River Rouge Station No. 1.	265	Peabody	R	Late 1972	Do.
9. Commonwealth Edison Co., Will County Station No. 1.	175	Babcock & Wilcox	R	February 1972	Guaranteed 90%.
10. Northern States Power Co., Sherburne County Station, Minn., No. 1.	700	Combustion Engineer.	N	1976	
11. Arizona Public Service, Cholla Station Co.	115	Research Cottrell	R	December 1973	
12. Tennessee Valley Authority, Widow's Creek Station No. 8.	550	Undecided	R	1974–75	
13. Duquesne Light Co., Philips Station.	100	Chemico	R	March 1973	Do.
14. Louisville Gas & Electric Co., Paddy's Run Station.	70	Combustion Engineer.	R	Mid-late 1972	Do.
15. City of Key West, Stock Island.[1]	37	Zurn	N	Early 1972	Guaranteed 85% removal.
16. Union Electric Co., Meramec No. 1.	125	Combustion Engineer.	R	Spring 1973	80% as target.
Sodium Hydroxide Scrubbing Installations:					
1. Nevada Power Co., Reed Gardner Station.	250	Combustion Equipment Associates.	R	1973	Guaranteed 90% SO_2 while burning 1% S coal.
Magnesium Oxide Scrubbing Installations:					
1. Boston Edison Co., Mystic Station No. 6.[2]	150	Chemico	R	February 1972	90% target.
2. Potomac Electric Power, Dickerson No. 3.	195	do	R	Early 1974	90%.
Catalytic Oxidation:					
1. Illinois Power, Wood River [2]	100	Monsanto	R	June 1972	Guaranteed 85% SO_2 removal.

[1] Oil-fired plants (remainder are coal-fired).
[2] Partial EPA funding.

All water from the pond is recycled back to the scrubber. Blowdown from cooling towers constitutes makeup water. The sludge oxidizes to sulfate in the pond. Eventually, sulfate may be removed from the system and taken with the ash to landfills.

The limestone system for the new 430-megawatt steam-electric unit at the Lawrence station is essentially the same as the smaller unit. It has been operated only on a limited basis to date. The company plans to operate at 65 percent SO_2 removal, then upgrade to 80 percent or more based on experience with the 125-megawatt unit. With the new system sulfate crystallization will be accomplished in tanks. The company plans to run clarified liquor from the crystallizers directly back to the scrubbers. A solids content of 6–10 percent will be maintained in the recycle liquor to prevent scaling in exposed surfaces.

Combustion engineering pilot studies. Pilot studies conducted by the Combustion Engineering Co. on a 1 mw. equivalent stream showed 95 percent SO_2 removal with continuous crystallization and 100 percent water recycle from crystallizers. The studies form the basis upon which CE is guaranteeing that its new installations will remove at least 70 percent of SO_2.

Battersea scrubber. The principle of alkaline scrubbing has been demonstrated at the Battersea Power Station in England, where a scrubber has been in use since 1932. A multiple stage process is employed. Alkaline river water is used in the first stage and lime-neutralized liquor in subsequent stages. The steam generator is of 3,500 million B.t.u. rating. Reports indicate that the efficiency of this system exceeds 90 percent when the boiler is fired with 0.8 to 1 percent sulfur coal. Similar systems are in operation on two 150-mw. oil-fired boilers at the Bankside Power Station in England.

Swansea scrubber. Lime scrubbing processes were installed on coal-fired units at the Swansea Power Station and the Fulham Power Station in England prior to World War II. The system at the Fulham Station reportedly operated successfully until shut down for security reasons early during World War II. It was not reactivated after the war. The Swansea installation was operated for about 2 years on a coal-fired power boiler

and is not now in service. Unlike the Battersea and Bankside operations, these units utilized a continuous liquid recycle. The systems were reported to operate at SO_2 efficiencies of 90 percent or greater.

Bahco lime scrubbing. The two-stage system has been demonstrated at about 93 percent SO_2 removal over a 6-month period on a 7-mw. oil-fired steam generator in Sweden. The process is now being offered under license in the United States by Research Cottrell. None of the Bahco systems have yet been installed on coal-fired boilers. Nevertheless, the two-stage scheme appears to offer definite advantages over single-stage processes in achieving high removal efficiencies.

Wellman power gas sulfite scrubbing. The sulfite-bisulfite system has been installed on two oil-fired boilers in Japan. The combined capacity is about 650 million B.t.u. per hour. Since it was put into operation in June 1971, removal efficiencies of 95 percent have been reported with exit levels of about 0.2 pounds SO_2 per million B.t.u. The system has not been operated on a coal-fired boiler. However, since precipitators have been shown to remove particulates down to the same level as oil-fired units, application of the sulfite system to coal-fired boilers should be feasible.

A principal difficulty in operating lime based scrubbing systems has been the tendency to form scale on scrubber surfaces. Union Electric, TVA, and to a lesser extent Kansas Power and Light have reported scaling problems. The experience of Kansas Power and Light and European and Japanese installations show that scaling can be held to a tolerable level. Present designs probably will be revised to optimize cost versus scaling. The use of two or more stages would appear desirable for high sulfur coals.

In all probability, there will be some scale formation in all closed circuit lime scrubbing systems for SO_2 abatement. At the Bahco installation as at the Kansas Power and Light installation in the United States, this is minimized by keeping the solution pH in the acid region. In addition to this, a Mitsubishi Heavy Industries pilot plant in Japan has employed seed crystals and a delay tank and was reportedly able to operate for 500 hours without any sign of scaling (i.e., the scaling took place on the seed crystals).

In addition to operating at an acid pH, the Bahco system employs a wide open scrubber that can tolerate appreciable scale deposits. It was reported that the installation of additional spray heads to more thoroughly wash the wetted surfaces at the Bischaff installation in West Germany helped to prevent scale formations.

All three installations cited above have reported successful periods of operation while employing the above-mentioned techniques. The most successful of these is the Bahco unit which has had no serious operational difficulties since November 1969. These examples show that lime systems can be operated without unscheduled shutdown due to scale problems.

3. *Cost of compliance with steam generator standards.* The economic impact of the new source performance standards and requisite pollution control expenditures have been developed for a typical new coal-fired unit of 600-megawatt (MW) capacity. The investment cost for such a plant would be $120 million plus $18 million for sulfur dioxide and particulate control and $1 million for nitrogen oxide control. The $19 million total can be compared to $3.6 million which would have been expended for particulate control if sulfur dioxide and nitrogen oxide abatement were not required.

On an annualized basis the pollution control costs would be 0.13 cents per kw.-hr. for sulfur dioxide and particulate control plus 0.01 cents per kw.-hr. for nitrogen oxide control. Particulate control alone would cost 0.01 cents per kw.-hr. An average revenue of 1.56 cents per kw.-hr. is assumed. Based on these figures, the cost of pollution control will be about 9 percent of the delivered cost of electricity if all plants operated by the utility in question had to incur a comparable cost. Using a figure of $130 per year as the average residential electric bill, the increased cost of electricity to a residential customer would be about $1 per month if the total cost of control is passed on to the customer.

An indication of the impact of increased electricity cost on industrial consumers may be obtained by examining the relationship of electricity cost to production costs. An upper limit may be approximated by considering the aluminum industry, a large consumer of electrical energy. If the aluminum industry were to incur an increase of nine percent in electricity cost, production costs would increase by about 1.4 percent. Although aluminum smelters usually consume hydroelectric power and would not realize pollution control costs increases, nonetheless, the figures show that even for a large consumer the impact of increased electricity cost is fairly small. In general, the estimated electricity cost increase will have only a minor impact on production costs.

Each year the power industry puts into operation about 49 new steam-electric units. On the average, 29 are fired with coal, seven with oil, and 13 with natural gas. Most of the oil-fired units and a few of the coal-fired units may burn low sulfur fuel. The number requiring flue gas desulfurization is estimated to be between 20 and 30 per year. Most of these, 15 to 20, will be located east of the Mississippi River.

The foregoing cost projections are based on estimated costs of $30 per installed kilowatt for sulfur dioxide scrubbing systems which will also be capable of controlling coal particulate to the level of the standard. Some power distributors have questioned the figure and suggest that the actual cost may be close to $70 per kw. Nevertheless, a review of applicable cost estimates for calcium base SO_2 scrubbing system shows support for the EPA estimate.

The four estimates listed in table II for new plants range from $18.7 to $25.67 per kw. Three of the plants are large—680 to 1,000 mw. All five estimates for retrofitting existing plants show greater cost, ranging from $28.6 to $61.8 per kw. The retrofit estimates tend to cover smaller steam generators, only one of the five being greater than 180 mw. In addition, the retrofit costs tend to reflect unusual circumstances which would not be expected at new plants. All are closed circuit limestone or calcium hydroxide systems except for the small unit at Key West, Fla. In the closed circuit system, all waters are recycled to avoid problems of liquid and solid waste disposal.

TABLE II

COST ESTIMATES FOR EQUIPPING COAL FIRED STEAM-ELECTRIC PLANTS WITH CALCIUM BASE SCRUBBING SYSTEMS (1971 ESTIMATES)

Source of estimate	Size	Capital cost
Zurn Industries (Key West installation).	37 MW (New).	$20.4/kw.
Northern States Power Co.	2-680 MW (New).	$18.7/kw.
Babcock & Wilcox (Hypothetical plant in midwest).	800 MW (New).	$25.67/kw.
Tennessee Valley Authority.	1000 MW (New).	$19.20/kw.
Do.	550 MW (Retrofit).	$54.5 to $61.8/kw.
Louisville Gas & Electric Co.	70 MW (Retrofit).	$28.6/kw.
Duquesne Light Co.	100 MW (Retrofit).	$35/kw.
Commonwealth Edison Co.	175 MW (Retrofit).	$49/kw.
Detroit Edison Co.	4-180 MW (Retrofit).	$49.6/kw.

Projected capital costs for nitrogen control will range from nil to $3.50 per kw. The greatest cost will be incurred from those units which will use combinations of flue gas recirculation and off-stoichiometric combustion to achieve the standard. Many of these will be gas-fired boilers which will not have to expend any capital for sulfur dioxide or particulate control. The least cost will be for corner-fired coal burning boilers which should be able to meet the standards without any modification. Corner-fired units are sold by only one of the four major U.S. power boiler manufacturers. The other three firms have experience with nitrogen oxide reduction schemes for gas and oil burning but it is uncertain what methods they will employ with coal burning. Consequently, precise costs are uncertain, but it is expected that the nitrogen oxide standard will stimulate interest in combustion techniques which can achieve the required emission levels at little or no increase in cost.

4. *The nitrogen oxide standard for coal-fired steam generators.* The standards set an emission limit of 0.7 pound of nitrogen oxide per million B.t.u. coal-fired steam generators. This is roughly equivalent to a stack gas concentration of 550 parts per million for a bituminous-fired operation. Several electric utilities and three of the four major boiler manufacturers commented that the technology was not fully demonstrated to achieve the standard.

The coal standard is based principally on nitrogen oxide levels achieved with corner-fired boilers which are manufactured by only one company—Combustion Engineering. This firm has confirmed in writing that it will guarantee to meet the nitrogen oxide standard. Investigations by an EPA contractor showed that other types of boilers could meet the standard under modified burning conditions. In fact, two of the three remaining companies have informed EPA they will guarantee that their new installations will meet the EPA standard of 0.7 pound/million B.t.u. on new installations.

5. *Particulate standards for kilns in portland cement plants.* Particulate emission limits of 0.3 pound per ton of feed to the kiln were proposed for cement kilns. This is roughly equivalent to a stack gas concentration of 0.03 grains per standard cubic foot.

The Portland Cement Association, American Mining Congress, a local control agency and the major cement producers commented that the kiln standard was either too strict or it is not based on adequately demonstrated technology, i.e. fabric filters can not be used for all types of cement plants. On the other hand, a comment was received from an equipment manufacturer stating that equipment other than fabric filters also can be used to meet the standard and citing supportive data for electrostatic precipitators. In addition, the AMC, a local agency and cement producers commented that the particulate standards for cement kilns are stricter than those promulgated for power plants and municipal incinerators. Further they objected to the test method to be used to determine compliance.

The proposed standard was based principally on particulate levels achieved at a kiln controlled by a fabric filter. Several other kilns controlled by fabric filters had no visible emissions but could not be tested due to the physical layout of the equipment. After proposal, but prior to promulgation a second kiln controlled by a fabric filter was tested and found to have particulate emissions in excess of the proposed standard. However, based on the revised particulate test method, the second installation showed particulate emissions to be less than 0.3 pound per ton of kiln feed.

The promulgated standard is roughly equivalent to a stack gas concentration of 0.03 grains per standard cubic foot. The power plant standard is equivalent to 0.06 grains per standard cubic foot at normal excess air rates. The incinerators standard is 0.08 grains per standard cubic foot corrected to 12 percent carbon dioxide. Uncorrected, at normal conditions of 7.5 percent carbon dioxide it is equivalent to 0.05 grains per standard cubic foot. The difference between the particulate standard for cement plants and those for steam generators and incinerators is attributable to the superior technology available therefor (that is, fabric filter technology has not been applied to coal-fired steam generators or incinerators).

In sum, considering the revision of the particulate test method, there are sufficient data to indicate that cement plants equipped with fabric filters and precipitators can meet the standard.

6. *Cost of achieving particulate standard for kilns at portland cement plants.* A limit of 0.3 pounds per ton of feed to the kiln was proposed. The limit applies to all new wet or dry process cement kilns.

Three cement producers commented that a well-controlled plant would cost much more than indicated by EPA. A meeting between American Mining Congress and EPA revealed that that association felt the cost of an uncontrolled cement plant as reported by EPA was low by a factor of 1.5 to 2. However, the association agreed that EPA had accurately estimated the cost of the pollution control equipment itself. Accordingly, no change in the standard was warranted on account of cost. Indeed, if the industry is correct in asserting that the cost of an uncontrolled plant is higher than that estimated by EPA, that means that the cost of pollution control expressed as a percentage of total cost is less than the 12 percent figure cited in the background document, APTD-0711, which was distributed by EPA at the time the standards were proposed.

7. *Sulfur dioxide and acid mist standards for sulfuric acid plants.* Sulfur dioxide emission limits of 4 pounds per ton of acid produced and acid mist emission limits of 0.15 pounds per ton of acid produced were proposed for sulfuric acid plants.

Several sulfuric acid manufacturers and the Manufacturing Chemists Association commented that the proposed SO_2 standard is unattainable in day-to-day operation at one of the plants tested or that it is unduly restrictive. They asserted that to meet the standard, the plant would have to be "designed to 2 pounds per ton" to allow for the inevitable gradual loss of conversion efficiency during a period of operation, and that units capable of such performance have not been demonstrated in this country. Essentially, the same parties commented that there is published data showing that due to the vapor pressure of sulfuric acid, the acid mist standard is not attainable.

The proposed standard was based principally on sulfur dioxide levels achieved with dual absorption acid plants and one single absorption plant controlling emissions with a sodium sulfite SO_2 recovery system. There are only three dual absorption plants in this country. Company emission data at one of the plants tested indicates the plant was meeting the proposed standard for a year of operation when the production rate was less than 600 tons per day. The plant is rated at 700 tons per day. At the second U.S. plant, emissions were about 2 pounds per ton about two months after startup. Discussion with foreign dual absorption plant designers and operators indicates normal operation at 99.8 percent conversion or higher for 99 percent of the time over a period of years. This conversion efficiency is equivalent to approximately 2.5 pounds per ton of acid produced.

Complaints from the industry that it cannot meet the acid mist standard appear to be based on experience with other test methods than EPA's. Such other methods measure more sulfur trioxide and acid vapor, in addition to acid mist, than does the EPA method. Tests of several plants with the EPA test method have shown acid mist emissions well below the emission limits as set in the standards.

8. *Cost of achieving sulfur dioxide standard at sulfuric acid plants.* A limit of 4 pounds of sulfur dioxide per ton of acid produced is set by the regulation. The limit applies to all types of new contact acid plants except those operated for control purposes, as at smelters.

The sulfuric acid industry has commented that (1) the cost of achieving the proposed sulfur dioxide standard is about three times the EPA estimate, and (2) promulgation of a standard 60 percent less restrictive than proposed by EPA would reduce the control cost 47 percent.

In developing the parallel cost estimates, both the industry and EPA assume the dual absorption process will be used to control sulfur burning plants and many spent acid plants. The more costly Wellman-Power Gas sulfite scrubbing system will be used with plants which process the most contaminated spent acid feedstocks where capital investment historically is 80 percent greater than sulfur burning plants. The Wellman-Power Gas process would also be used for retrofitting existing plants where appropriate. Both the dual absorption and Wellman-Power Gas processes have been demonstrated on commercial installations. Seventy-six dual absorption plants have been constructed or designed since the first in 1964. Only three, however, are located in this country. One sulfite scrubbing process is now in operation in the United States and four more will be put into service in 1972. All are retrofit installations. Two other such scrubbers are being operated in Japan. These seven installations consist of three acid plants, two claus sulfur recovery plants, an oil-fired boiler, and a kraft pulp mill boiler.

Control costs. EPA engineers have reviewed the industry analysis and find no reason to change their original cost estimate. As summarized in Table III, EPA estimates that the cost of achieving the standard is $1.07 to $1.32 per ton of acid for dual absorption systems and $3.50 per ton for sulfite scrubbing systems. The industry estimate for a sulfur burning dual absorption plant is $2.31 greater than EPA's. We believe the industry's estimate to be excessive for the following reasons.

TABLE III

ESTIMATED COSTS OF CONTROLLING SULFUR DIOXIDE FROM CONTACT SULFURIC ACID PLANTS

	Dual absorption process		Sodium sulfite scrubbing	
	Industry	EPA	Industry	EPA
Sulfur burning plants:				
Direct Investment (Thousands of $)	2,000	550	Not anticipated for new sulfur burning plants.	
Total Added Cost ($/Ton)a)	3.38	1.07		
Spent acid plants:				
Direct Investment (Thousands of $)	3,100	900	2,200	2,300
Total Added Cost ($/Ton)a)	4.45	1.32	4.11	3.50

a) Total added cost includes depreciation, taxes, 16% return on investment after taxes and other allocated costs.

Seventy-two percent of the difference between the Du Pont and EPA estimates is due to direct investment, plant overhead, and operating costs for auxiliary process and storage equipment which Du Pont predicts will be necessary to satisfy the standards. EPA does not believe that such auxiliary equipment will be necessary in practice to meet the standard.

Twenty percent of the difference is due to differences in estimates of the cost and consumption of utilities. Elimination of auxiliary equipment referred to above reduces the consumption rate of both electricity and steam. Eight percent results from the industry's apportionment of "other allocated costs" (Corporate Administration, i.e., sales, research, and development, main office, etc.) in proportion to their estimate of the additional investment required for control. Although an accepted procedure for internal cost accounting, this does not represent a true out-of-pocket cost.

In sum, the EPA analysis shows that meeting the proposed standard with a dual absorption plant requires a substantial investment over an uncontrolled plant but only 30 percent as great as indicated by the industry. Moreover, relaxation of the proposed standard by 60 percent (to the level recommended by the industry) would decrease the cost of control in dual absorption plants only 10 to 15 percent. For sulfur burning plants the cost differential would be $0.10 per ton of acid. For spent acid plants, it would be $0.17.

Economic impact of proposed standard. Most sulfuric acid production is captive to large vertically integrated chemical, petroleum, or fertilizer manufacturers. An increasing volume of production also results from the recovery of sulfur dioxide from stack gases or the regeneration of spent acid instead of its discharge into streams.

Depending on the abatement process selected and the plant size, the direct investment for control can range from 14 to 38 percent of the investment in an uncontrolled acid plant.

The added cost of air pollution control, coupled with the inherent market disadvantage of the small manufacturer, may make future construction of plants of less than 500 tons per day economically unattractive except as a sulfur recovery system for another manufacturing process.

It is estimated that the average market price will increase by $1.07 per ton reflecting the lower end of the cost range. This represents a small increase in the $31 per ton market price and will have little effect on the demand for acid.

The increasing production of recovered and regenerated acid, as a result of abatement efforts, will inhibit the growth of conventional acid production and threaten eventually to displace much of that production.

WILLIAM D. RUCKELSHAUS,
Administrator.

MARCH 16, 1972.

[FR Doc.72-4338 Filed 3-20-72;8:51 am]

2 Title 40—PROTECTION OF ENVIRONMENT

Chapter I—Environmental Protection Agency

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Standard for Sulfur Dioxide; Correction

The new source performance standard published December 23, 1971 (36 F.R. 24876), which is applicable to sulfur dioxide emissions from fossil-fuel fired steam generators, incorrectly omits provision for compliance by burning natural gas in combination with oil or coal. Accordingly, in § 60.43 of Title 40 of the Code of Federal Regulations, paragraph (c) is revised and a new paragraph (d) is added, as follows:

§ 60.43 *Standard for sulfur dioxide.*

* * * * *

(c) Where different fossil fuels are burned simultaneously in any combination, the applicable standard shall be determined by proration using the following formula:

$$\frac{y(0.80) + z(1.2)}{y + z}$$

where:

y is the percent of total heat input derived from liquid fossil fuel and,
z is the percent of total heat input derived from solid fossil fuel.

(d) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

This amendment shall be effective upon publication in the FEDERAL REGISTER (7-25-72).

Dated: July 19, 1972.

JOHN QUARLES, Jr.,
Acting Administrator.

[FR Doc.72-11381 Filed 7-25-72;8:49 am]

3 SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Amendment to Standards for Opacity and Corrections to Certain Test Methods

On December 23, 1971, pursuant to section 111 of the Clean Air Act, as amended, 40 CFR part 60 was adopted establishing regulations for the control of air pollution from new cement plants, sulfuric acid plants, nitric acid plants, municipal incinerators, and fossil-fuel-fired steam generators. The standards included opacity limits for visible air pollution emissions; 40 CFR 60 is being amended to clarify the application of opacity standards. The revisions do not alter the stringency of the regulation.

It was EPA's intention that condensed water not be considered a visible air contaminant for purposes of new source performance standards. Condensed water was specifically exempted from the opacity limits promulgated for steam generators and cement plants. Nitric acid plants and sulfuric acid plants were not exempted since there is normally little water vapor in stack gases from these sources. However, under certain weather conditions, scrubbers will generate a visible plume of condensed water. Therefore, in order to clarify enforcement procedures, provisions are being added to exempt condensed water from opacity limits for sulfuric acid plants and for nitric acid plants.

The appendix to part 60 incorrectly presents certain data and equations. These typing/printing errors are being corrected.

This amendment makes certain clarifications and corrections but does not change the substance of the regulation. Therefore, the Administrator has determined that it is unnecessary to publish a notice of proposed rulemaking or delay the effective date of this amendment and for this good cause has not done so.

This amendment shall be effective May 23, 1973.

Dated May 16, 1973.

ROBERT W. FRI,
Acting Administrator.

Part 60, chapter I, title 40, Code of Federal Regulations, is amended as follows:

1. In § 60.72, a new paragraph (c) is added as follows:

§ 60.72 Standards for nitrogen oxides.

* * * * *

(c) Where the presence of uncombined water is the only reason for failure to meet the requirements of paragraph (b) of this section, such failures shall not be considered a violation of this section.

2. In § 60.83, a new paragraph (c) is added as follows:

§ 60.83 Standards for acid mist.

* * * * *

(c) Where the presence of uncombined water is the only reason for failure to meet the requirement of paragraph (b) of this section, such failure shall not be considered a violation of this section.

3. Table 1-1 in method 1 of the appendix to part 60 is revised to read as follows:

4. Equations 5-2 and 5-6 in method 5 of the appendix are revised to read as follows:

Table 1-1. Location of traverse points in circular stacks
(Percent of stack diameter from inside wall to traverse point)

Traverse point number on a diameter	Number of traverse points on a diameter											
	2	4	6	8	10	12	14	16	18	20	22	24
1	14.6	6.7	4.4	3.3	2.5	2.1	1.8	1.6	1.4	1.3	1.1	1.1
2	85.4	25.0	14.7	10.5	8.2	6.7	5.7	4.9	4.4	3.9	3.5	3.2
3		75.0	29.5	19.4	14.6	11.8	9.9	8.5	7.5	6.7	6.0	5.5
4		93.3	70.5	32.3	22.6	17.7	14.6	12.5	10.9	9.7	8.7	7.9
5			85.3	67.7	34.2	25.0	20.1	16.9	14.6	12.9	11.6	10.5
6			95.6	80.6	65.8	35.5	26.9	22.0	18.8	16.5	14.6	13.2
7				89.5	77.4	64.5	36.6	28.3	23.6	20.4	18.0	16.1
8				96.7	85.4	75.0	63.4	37.5	29.6	25.0	21.8	19.4
9					91.8	82.3	73.1	62.5	38.2	30.6	26.1	23.0
10					97.5	88.2	79.9	71.7	61.8	38.8	31.5	27.2
11						93.3	85.4	78.0	70.4	61.2	39.3	32.3
12						97.9	90.1	83.1	76.4	69.4	60.7	39.8
13							94.3	87.5	81.2	75.0	68.5	60.2
14							98.2	91.5	85.4	79.6	73.9	67.7
15								95.1	89.1	83.5	78.2	72.8
16								98.4	92.5	87.1	82.0	77.0
17									95.6	90.3	85.4	80.6
18									98.6	93.3	88.4	83.9
19										96.1	91.3	86.8
20										98.7	94.0	89.5
21											96.5	92.1
22											98.9	94.5
23												96.8
24												98.9

$$V_{w_{std}} = V_{l_c} \frac{\rho H_2O}{M_{H_2O}} \frac{RT_{std}}{P_{std}} \frac{\text{lb.}}{454 \text{ gm.}}$$

$$= 0.0474 \frac{\text{cu. ft.}}{\text{ml.}} V_{l_c}$$

equation 5-2

$$I = \frac{T_s \left[\left(\frac{0.00267 \text{ in. Hg-cu. ft.}}{\text{ml} - {}^\circ\text{R}} \right) V_{l_c} + \frac{V_m}{T_m} \left(P_{bar} + \frac{H}{13.6} \right) \right] \left(1.667 \frac{\text{min.}}{\text{sec.}} \right)}{\theta V_s P_s A_n}$$

equation 5-6

[FR Doc.73-10061 Filed 5-22-73;8:45 am]

4

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Emissions During Startup, Shutdown, and Malfunction

The Environmental Protection Agency promulgated Standards of Performance for New Stationary Sources pursuant to section 111 of the Clean Air Act Amend-

ments of 1970, 40 U.S.C. 1857c–6, on December 23, 1971, for fossil fuel-fired steam generators, incinerators, Portland cement plants, and nitric and sulfuric acid plants (36 F.R. 24876), and proposed Standards of Performance on June 11, 1973, for asphalt concrete plants, petroleum refineries, storage vessels for petroleum liquids, secondary lead smelters, secondary brass and bronze ingot production plants, iron and steel plants, and sewage treatment plants (38 FR 15406). New or modified sources in these categories are required to meet standards for emissions of air pollutants which reflect the degree of emissions limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated.

Sources which ordinarily comply with the standards may during periods of startup, shutdown, or malfunction unavoidably release pollutants in excess of the standards. These regulations make it clear that compliance with emission standards, other than opacity standards, is determined through performance tests conducted under representative conditions. It is anticipated that the initial performance test and subsequent performance tests will ensure that equipment is installed which will permit the standards to be attained and that such equipment is not allowed to deteriorate to the point where the standards are no longer maintained. In addition, these regulations require that the plant operator use maintenance and operating procedures designed to minimize emissions. This requirement will ensure that plant operators properly maintain and operate the affected facility and control equipment between performance tests and during periods of startup, shutdown, and unavoidable malfunction.

The Environmental Protection Agency on August 25, 1972, proposed procedures pursuant to which new sources could be deemed not to be in violation of the new source performance standards if emissions during startup, shutdown, and malfunction unavoidably exceed the standards (37 FR 17214). Comments received were strongly critical of the reporting requirements and the lack of criteria for determining when a malfunction occurs.

In response to these comments, the Environmental Protection Agency rescinded the August 25, 1972, proposal and published a new proposal on May 2, 1973 (38 FR 17214). The purpose and reasoning in support of the May 2, 1973, proposal are set forth in the preamble to the proposal. As these regulations being promulgated are in substance the same as those of the May 2, 1973, proposal, this preamble will discuss only the comments received in response to the proposal and changes made to the proposal. *

A total of 28 responses were received concerning the proposal (38 FR 10820). Twenty-one responses were received from the industrial sector, three from State and local air pollution control agencies, and four from EPA representatives.

Some air pollution control agencies expressed a preference for more detailed reporting and for requiring reporting immediately following malfunctions and preceding startups and shutdowns in order to facilitate handling citizens' complaints and emergency situations. Since States already have authority to require such reporting and since promulgation of these reporting requirements does not preclude any State from requiring more detailed or more frequent reporting, no changes were deemed necessary.

Some comments indicated that changes were needed to more specifically define those periods of emissions that must be reported on a quarterly basis. The regulations have been revised to respond to this comment. Those periods which must be reported are defined in applicable subparts. Continuous monitoring measurements will be used for determining those emissions which must be reported. Periods of excess emissions will be averaged over specified time periods in accordance with appropriate subparts. Automatic recorders are currently available that produce records on magnetic tapes that can be processed by a central computing system for the purpose of arriving at the necessary averages. By this method and by deletion of requirements for making emission estimates, only minimal time will be required by plant operators in preparing quarterly reports. The time period for making quarterly reports has been extended to 30 days beyond the end of the quarter to allow sufficient time for preparing necessary reports.

The May 2, 1973, proposal required that affected facilities be operated and maintained "in a manner consistent with operations during the most recent performance test indicating compliance." Comments were received questioning whether it would be possible or wise to require that all of the operating conditions that happened to exist during the most recent performance test be continually maintained. In response to these comments, EPA revised this requirement to provide that affected facilities shall be operated and maintained "in a manner consistent with good air pollution control practice for minimizing emissions" (§ 60.11(d)).

Comments were received indicating concern that the proposed regulations would grant license to sources to continue operating after malfunctions are detected. The provision of § 60.11(d) requires that good operating and maintenance practices be followed and thereby precludes continued operation in a malfunctioning condition.

This regulation is promulgated pursuant to sections 111 and 114 of the Clean Air Act as amended (42 U.S.C. 1857c–b, 1857c–9).

This amendment is effective November 14, 1973.

Dated October 10, 1973.

JOHN QUARLES,
Acting Administrator.

Part 60 of Title 40, Code of Federal Regulations is amended as follows:

1. Section 60.2 is amended by adding paragraphs (p), (q), and (r) as follows:

§ 60.2 Definitions.

* * * * *

(p) "Shutdown" means the cessation of operation of an affected facility for any purpose.

(q) "Malfunction" means any sudden and unavoidable failure of air pollution control equipment or process equipment or of a process to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

(r) "Hourly period" means any 60 minute period commencing on the hour.

2. Section 60.7 is amended by adding paragraph (c) as follows:

§ 60.7 Notification and recordkeeping.

* * * * *

(c) A written report of excess emissions as defined in applicable subparts shall be submitted to the Administrator by each owner or operator for each calendar quarter. The report shall include the magnitude of excess emissions as measured by the required monitoring equipment reduced to the units of the applicable standard, the date, and time of commencement and completion of each period of excess emissions. Periods of excess emissions due to startup, shutdown, and malfunction shall be specifically identified. The nature and cause of any malfunction (if known), the corrective action taken, or preventive measures adopted shall be reported. Each quarterly report is due by the 30th day following the end of the calendar quarter. Reports are not required for any quarter unless there have been periods of excess emissions.

3. Section 60.8 is amended by revising paragraph (c) to read as follows:

§ 60.8 Performance tests.

* * * * *

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions of performance tests unless otherwise specified in the applicable standard.

4. A new § 60.11 is added as follows:

§ 60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined only by performance tests established by § 60.8.

*May 2, 1973 Preamble immediately follows these revisions.

(b) Compliance with opacity standards in this part shall be determined by use of Test Method 9 of the appendix.

(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

5. A new paragraph is added to § 60.45 as follows:

§ 60.45 Emission and fuel monitoring.

* * * * *

(g) For the purpose of reports required pursuant to § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Opacity. All hourly periods during which there are three or more one-minute periods when the average opacity exceeds 20 percent.

(2) Sulfur dioxide. Any two consecutive hourly periods during which average sulfur dioxide emissions exceed 0.80 pound per million B.t.u. heat input for liquid fossil fuel burning equipment or exceed 1.2 pound per million B.t.u. heat input for solid fossil fuel burning equipment; or for sources which elect to conduct representatives analyses of fuels in accordance with paragraph (c) or (d) of this section in lieu of installing and operating a monitoring device pursuant to paragraph (a) (2) of this section, any calendar day during which fuel analysis shows that the limits of § 60.43 are exceeded.

(3) Nitrogen oxides. Any two consecutive hourly periods during which the average nitrogen oxides emissions exceed 0.20 pound per million B.t.u. heat input for gaseous fossil fuel burning equipment, or exceed 0.30 pound per million B.t.u. for liquid fossil fuel burning equipment, or exceed 0.70 pound per million B.t.u. heat input for solid fossil fuel burning equipment.

6. A new paragraph is added to § 60.73 as follows:

§ 60.73 Emission monitoring.

* * * * *

(e) For the purpose of making written reports pursuant to § 60.7(c), periods of excess emissions that shall be reported are defined as any two consecutive hourly periods during which average nitrogen oxides emissions exceed 3 pounds per ton of acid produced.

7. A new paragraph is added to § 60.84 as follows:

§ 60.84 Emission monitoring.

* * * * *

(e) For the purpose of making written reports pursuant to § 60.7(c), periods of excess emissions that shall be reported are defined as any two consecutive hourly periods during which average sulfur dioxide emissions exceed 4 pounds per ton of acid produced.

[FR Doc.73-21896 Filed 10-12-73;8:45 am]

4A

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 60]

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Emissions During Startup, Shutdown and Malfunction

The Environmental Protection Agency promulgated standards of performance for new stationary sources pursuant to section 111 of the Clean Air Amendments of 1970, 40 U.S.C. 1857c-6, on December 23, 1971, for fossil fuel-fired steam generators, incinerators, portland cement plants, and nitric and sulfuric acid plants (36 FR 24876). New or modified sources in those categories are required to meet standards for emissions of air pollutants which reflect the degree of emissions limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determined to be adequately demonstrated.

On August 25, 1972, the Environmental Protection Agency proposed procedures pursuant to which new sources could be deemed not to be in violation of the new source performance standards if emissions during startup, shutdown and malfunction unavoidably exceeded the standards (37 FR 17214). A total of 141 responses were received during the period allowed for official comment on the proposal. Comments received were strongly critical of the various reporting requirements, and the lack of more specific criteria for granting exceptions to the standards. A number of comments were directed toward EPA's policy on delegating enforcement of these procedures to the States as provided under section 111 of the Clean Air Act. This new proposal is intended to respond to these criticisms. The August 25, 1972, proposal is hereby withdrawn.

Attempts to classify all of the situations in which excess emissions due to malfunction, startup and shutdown could occur and the amount and duration of excess emission from each such situation indicated that it is not feasible to provide quantitative standards or guides which would apply to periods of malfunctions, startups and shutdowns.

Comments received in response to the proposal, however, strongly emphasized the difficulties in planning and financing new sources when no assurance could be made that the sources would be in compliance with the standards or would

be granted a waiver in those cases where failure to meet the standard was not the fault of the plant owner or operator. Accordingly, the approach described below is now proposed by EPA. This approach will ensure that new sources install the best adequately demonstrated technology and operate and maintain such equipment to keep emissions as low as possible.

The proposed regulations make it clear that compliance with emission standards, other than opacity standards, is determined through performance tests conducted under representative conditions. The present tests for new sources require that initial performance tests be conducted within 60 days after achieving the maximum production rate at which a facility will be operated but not later than 180 days after startup and authorizes subsequent tests from time to time as required by the Administrator. It is anticipated that the initial performance test and subsequent performance tests will ensure that equipment is installed which will permit the standards to be attained and that such equipment is not allowed to deteriorate to the point where the standards are no longer maintained. In addition, the proposed regulation requires that the plant operator use maintenance and operating procedures designed to minimize emissions in excess of the standard. This requirement will ensure that plant operators properly maintain and operate the affected facility and control equipment between performance tests and during periods of startup, shutdown and unavoidable malfunction.

Although the requirements in the present regulations for continuous monitoring will be unaffected by these proposed regulations, it is made clear that measurements obtained as the results of such monitoring will be used as evidence in determining whether good maintenance and operating procedures are being followed. They will not be used to determine compliance with mass emission standards unless approved as equivalent or alternative method for performance testing. EPA may in the future require that compliance with new source emissions standards be determined by continuous monitoring. In such cases, the applicable standard will specifically require that compliance with mass emission limits be determined by continuous monitoring. Such standards will provide for malfunction, startup and shutdown situations to the extent necessary.

With respect to the opacity standards, a different approach was used because this is a primary means of enforcement using visual surveillance employed by State and Federal officials. EPA believes that the burden should remain on the plant operator to justify a failure to comply with opacity standards. This difference is justified because determination of mass emission levels requires close contact with plant personnel, operations and records and the burden imposed on enforcement agencies to determine whether good maintenance and operating procedures have been followed is not significantly greater than the burden of determining mass emission levels. However, opacity observations are taken outside the plant and do not require contact with plant personnel, operations or records, and the burden of determining whether good maintenance and operating procedures have been followed would be much greater than determining whether opacity standards have been violated. Nevertheless, EPA has recognized that malfunctions, startups and shutdowns may result in the opacity emission levels being exceeded. Accordingly, the standards will not apply in such cases. However, the burden will be upon the plant operator rather than EPA or the States to show that the opacity standards were not met because of such situations. In the event of any dispute, the owner or operator of the source may seek review in an appropriate court.

The reporting requirements in these proposed regulations have been greatly simplified. They require only that at the end of each calendar quarter owners and operators report emissions measured or estimated to be greater than those allowable under standards applicable during performance tests.

EPA believes that the proposed reporting requirements along with application of the opacity standards will provide adequate information to enable EPA and the States to effectively enforce the new source performance standards. Additional information and shorter reporting times would not materally increase enforcement capability and could, in fact, hinder such efforts due to the additional time and manpower required to process the information.

The primary purpose of the quarterly report is to provide EPA and the States with sufficient information to determine if further inspection or performance tests are warranted. It should be noted that the Administrator can delegate enforcement of the standards to the States as provided by section 111(c)(1) of the Clean Air Act, as amended. Procedures for States to request this delegation are available from EPA regional offices. It is EPA's policy that upon delegation any reports required by these proposed regulations will be sent to the appropriate State. (A change in the address for submittal of reports as provided in 40 CFR 60.4 will be made after each delegation.)

These proposed regulations will have no significant adverse impact on the public health and welfare. Those sections of the Clean Air Act which are specifically required to protect the public health and welfare, sections 109 and 110 (National Ambient Air Quality Standards and their implementation), section 112 (National Emission Standards for Hazardous Air Pollutants), and section 303 (Emergency Powers to Stop the Emissions of Air Pollutants Presenting an Imminent and Substantial Endangerment to the Health of Persons), will be unaffected by these new proposed regulations and will continue to be effective controls protecting the public health and welfare.

Interested persons may participate in this proposed rulemaking by submitting written comment in triplicate to the Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711, Attention: Mr. Don R. Goodwin, All relevant comments received not later than June 18, 1973, will be considered. Receipt of comments will be acknowledged but the Emission Standards and Engineering Division will not provide substantial response to individual comments. Comments received will be available for public inspection during normal business hours at the Office of Public Affairs, 401 M Street SW., Washington, D.C. 20460.

This notice of proposed rulemaking is issued under the authority of sections 111 and 114 of the Clean Air Act, as amended (42 U.S.C. 1857c–6, 1857c–9).

Dated April 27, 1973.

JOHN QUARLES,
Acting Administrator,
Environmental Protection Agency.

5 Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Additions and Miscellaneous Amendments

On June 11, 1973 (38 FR 15406), pursuant to section 111 of the Clean Air Act, as amended, the Administrator proposed standards of performance for new and modified stationary sources within seven categories of stationary sources: (1) Asphalt concrete plants, (2) petroleum refineries, (3) storage vessels for petroleum liquids, (4) secondary lead smelters, (5) secondary brass and bronze ingot production plants, (6) iron and steel plants, and (7) sewage treatment plants. In the same publication, the Administrator also proposed amendments to subpart A, General Provisions, and to the Appendix, Test Methods, of 40 CFR Part 60.

Interested parties participated in the rulemaking by sending comments to EPA. Some 253 letters, many with multiple comments, were received from commentators, and about 152 were received from Congressmen making inquiries on behalf of their constituents. Copies of the comments received directly are available from public inspection at the EPA Office of Public Affairs, 401 M Street SW., Washington, D.C. 20460. The comments have been considered, additional data have been collected and assessed, and the standards have been reevaluated. Where determined by the Administrator to be appropriate, revisions have been made to the proposed standards. The promulgated standards, the principal revisions to the proposed standards, and the Agency's responses to major comments are summarized below. More detail may be found in *Background Information for New Source Performance Standards: Asphalt Concrete Plants, Petroleum Refineries, Storage Vessels, Secondary Lead Smelters and Refineries, Brass and Bronze Ingot Production Plants, Iron and Steel Plants, and Sewage Treatment Plants*, Volume 3, *Promulgated Standards*, (APTD–1352c) which is available on request from the Emission Standards and Engineering Division, Research Triangle Park, North Carolina 27711, Attention: Mr. Don R. Goodwin.

Discussions of the environmental impact of these standards of performance for new sources are contained in Volume 1, Main Text (APTD–1352a), of the background document. This volume and Volume 2, *Appendix: Summaries of Test Data* (APTD–1352b), are still available on request from the office noted above.

In accordance with section 111 of the Act, these regulations prescribing standards of performance for the selected stationary sources are effective on February 28, 1974 and apply to sources the construction or modification of which was commenced after June 11, 1973.

General Provisions

These promulgated regulations include changes to subpart A, General Provisions, which applies to all new sources. The general provisions were published on December 23, 1971 (36 FR 24876). The definition of "commenced" has been altered to exclude the act of entering into a binding agreement to construct or modify a source from among the specified acts which, if taken by an owner or operator of a source on or after the date on which an applicable new source performance standard is proposed, cause the source to be subject to the promulgated standard. The phrase "binding agreement" was duplicate terminology for the phrase "contractual obligation" but was being construed incorrectly to apply to other arrangements. Deletion of the first phrase and retention of the second phrase eliminates the problem. The definition of "standard conditions" replaces the definition of "standard or normal conditions" to avoid the confusion, noted by commentators, created by the duplicate terminology. The promulgated definition also expresses the temperature and pressure in commonly used metric units to be consistent with the Administrator's policy of converting to the metric system. Four definitions are added: "Reference method," "equivalent method," "alternative method," and "run," to clarify the terms used in changes to § 60.8, Performance Tests, discussed below. The definition of "particulate matter" is added here and removed from each of the subparts specific to this group of new sources to avoid repetition. The word "run," as used in the sections pertinent to performance tests, is defined as the net time required to collect an adequate sample of a pollutant, and may be either intermittent or continuous. Section 60.3, Abbreviations, is revised to include new abbreviations, to accord more closely with standard usage, and to alphabetize the listing. Section 60.4, Address, is revised to change the address to which all requests, reports, applications, submittals, and other communications will be submitted to the Administrator pursuant to any regulatory provision. Such communications are now to be addressed to the Director of the Enforcement Division in the appropriate EPA regional office rather than to the Office of General Enforcement in Washington, D.C. The addresses of all 10 regional offices are included, and the "in triplicate" requirement is changed to "in duplicate." Some of the wording is changed in § 60.6, Review of Plans, to require that owners or operators requesting review of plans for construction or modification make a separate request for each project rather than for each affected facility as previously required; each such facility, however, must be identified and appropriately described. A paragraph is added to § 60.7, Notification and Recordkeeping, to require owners and operators to maintain a file of all recorded information required by the regulations for at least 2 years after the dates of such information, and this requirement is removed from the subparts specific to each of the new sources in this group to avoid repetition. Section 60.8, Performance Tests, is amended (1) to require owners and operators to give the Administrator 30 days' advance notice, instead of 10 days', of performance testing to demonstrate compliance with standards in order to provide the Administrator with a better opportunity to have an observer present, (2) to specify the Administrator's authority to permit, in specific cases, the use of minor changes to reference methods, the use of equivalent or alternative methods, or the waiver of the performance test requirement, and (3) to specify that each performance test shall consist of three runs except where the Administrator approves the use of two runs because of circumstances beyond the control of the owner or operator. These amendments give the Administrator needed flexibility for making judgments for determining compliance with standards. Section 60.12, Circumvention, is added to clearly prohibit owners and operators from using devices or techniques which conceal, rather than control, emissions to comply with standards of performance for new sources. The standards proposed on June 11, 1973, contained provisions which required compliance to be based on undiluted gases. Many commentators pointed out the inequities of these provisions and the vagueness of the language used. Because many processes require the addition of air in various quantities for cooling, for enhancing combustion, and for other useful purposes, no single definition of excess dilution air can be sensibly applied. It is considered preferable to state clearly what is prohibited and to use the Administrator's authority to specify the conditions for compliance testing in each case to ensure that the prohibited concealment is not used.

Opacity

It is evident from comments received that an inadequate explanation was given for applying both an enforceable opacity standard and an enforceable concentration standard to the same source and that the relationship between the concentration standard and the opacity standard was not clearly presented. Because all but one of the regulations include these dual standards, this subject is dealt with here from the general viewpoint. Specific changes made to the regulations proposed for a specific source are described in the discussions of each source.

A discussion of the major points raised by the comments on the opacity standard follows:

1. Several commentators felt that opacity limits should be only guidelines for determining when to conduct the stack tests needed to determine compliance with concentration/mass standards. Several other commentators expressed the opinion that the opacity standard was more stringent than the concentration/mass standard.

As promulgated below, the opacity standards are regulatory requirements, just like the concentration/mass standards. It is not necessary to show that the concentration/mass standard is being violated in order to support enforcement of the opacity standard. Where opacity and concentration/mass standards are

applicable to the same source, the opacity standard is not more restrictive than the concentration/mass standard. The concentration/mass standard is established at a level which will result in the design, installation, and operation of the best adequately demonstrated system of emission reduction (taking costs into account) for each source. The opacity standard is established at a level which will require proper operation and maintenance of such control systems on a day-to-day basis, but not require the design and installation of a control system more efficient or expensive than that required by the concentration/mass standard.

Opacity standards are a necessary supplement to concentration/mass standards. Opacity standards help ensure that sources and emission control systems continue to be properly maintained and operated so as to comply with concentration/mass standards. Particulate testing by EPA method 5 and most other techniques requires an expenditure of $3,000 to $10,000 per test including about 300 man-hours of technical and semi-technical personnel. Furthermore, scheduling and preparation are required such that it is seldom possible to conduct a test with less than 2 weeks notice. Therefore, method 5 particulate tests can be conducted only on an infrequent basis.

If there were no standards other than concentration/mass standards, it would be possible to inadequately operate or maintain pollution control equipment at all times except during periods of performance testing. It takes 2 weeks or longer to schedule a typical stack test. If only small repairs were required, e.g., pump or fan repair or replacement of fabric filter bags, such remedial action could be delayed until shortly before the test is conducted. For some types of equipment such as scrubbers, the energy input could be reduced (the pressure drop through the system) when stack tests weren't being conducted, which would result in the release of significantly more particulate matter than normal. Therefore, EPA has required that operators properly maintain air pollution control equipment at all times (40 CFR 60.11 (d)) and meet opacity standards at all times except during periods of startup, shutdown, and malfunction (40 CFR 60.11(c)), and during other periods of exemption as specified in individual regulations.

Opacity of emissions is indicative of whether control equipment is properly maintained and operated. However, it is established as an independent enforceable standard, rather than an indicator of maintenance and operating conditions because information concerning the latter is peculiarly within the control of the plant operator. Furthermore, the time and expense required to prove that proper procedures have not been followed are so great that the provisions of 40 CFR 60.11(d) by themselves (without opacity standards) would not provide an economically sensible means of ensuring on a day-to-day basis that emissions of pollutants are within allowable limits. Opacity standards require nothing more than a trained observer and can be performed with no prior notice. Normally, it is not even necessary for the observer to be admitted to the plant to determine properly the opacity of stack emissions. Where observed opacities are within allowable limits, it is not normally necessary for enforcement personnel to enter the plant or contact plant personnel. However, in some cases, including times when opacity standards may not be violated, a full investigation of operating and maintenance conditions will be desirable. Accordingly, EPA has requirements for both opacity limits and proper operating and maintenance procedures.

2. Some commentators suggested that the regulatory opacity limits should be lowered to be consistent with the opacity observed at existing plants; others felt that the opacity limits were too stringent. The regulatory opacity limits are sufficiently close to observed opacity to ensure proper operation and maintenance of control systems on a continuing basis but still allow some room for minor variations from the conditions existing at the time opacity readings were made.

3. There are specified periods during which opacity standards do not apply. Commentators questioned the rationale for these time exemptions, as proposed, some pointing out that the exemptions were not justified and some that they were inadequate. Time exemptions further reflect the stated purpose of opacity standards by providing relief from such standards during periods when acceptable systems of emission reduction are judged to be incapable of meeting prescribed opacity limits. Opacity standards do not apply to emissions during periods of startup, shutdown, and malfunction (see FEDERAL REGISTER of October 15, 1973, 38 FR 28564), nor do opacity standards apply during periods judged necessary to permit the observed excess emissions caused by soot-blowing and unstable process conditions. Some confusion resulted from the fact that the startup-shutdown-malfunction regulations were proposed separately (see FEDERAL REGISTER of May 2, 1973, 38 FR 10820) from the regultions for this group of new sources. Although this was pointed out in the preamble (see FEDERAL REGISTER of June 11, 1973, 38 FR 15406) to this group of new source performance standards, it appears to have escaped the notice of several commentators.

4. Other comments, along with restudy of sources and additional opacity observations, have led to definition of specific time exemptions, where needed, to account for excess emissions resulting from soot-blowing and process variations. These specific actions replace the generalized approach to time exemptions, 2 minutes per hour, contained in all but one of the proposed opacity standards. The intent of the 2 minutes was to prevent the opacity standards from being unfairly stringent and reflected an arbitrary selection of a time exemption to serve this purpose. Comments noted that observed opacity and operating conditions did not support this approach. Some pointed out that these exemptions were not warranted; others, that they were inadequate. The cyclical basic oxygen steel-making process, for example, does not operate in hourly cycles and the inappropriateness of 2 minutes per hour in this case would apply to other cyclical processes which exist both in sources now subject to standards of performance and sources for which standards will be developed in the future. The time exemptions now provide for circumstances specific to the sources and, coupled with the startup-shutdown-malfunction provisions and the higher-than-observed opacity limits, provide much better assurance that the opacity standards are not unfairly stringent.

ASPHALT CONCRETE PLANTS

The promulgated standards for asphalt concerete plants limit particulate matter emissions to 90 mg/dscm (0.04 gr/dscf and 20 percent opacity.

The majority of the comments received on the seven proposed standards related to the proposed standards for asphalt concrete plants. Out of the 253 letters, over 65 percent related to the proposed standards for asphalt concrete plants. Each of the comments was reviewed and evaluated. The Agency's responses to the comments received are included in Appendix E of Volume 3 of the background information document. The Agency's rationale for the promulgated standards for asphalt concrete plants is summarized below. A more detailed statement is presented in Volume 3 of the background information document.

The major differences between the proposed standards and the promulgated standards are:

1. The concentration standard has been changed from 70 mg/dscm (0.031 gr/dscf) to 90 mg/dscm (0.04 gr/dscf).

2. The opacity standard has been changed from 10 percent with a 2-minute-per-hour exemption to 20 percent with no specified time exemption.

3. The definition of affected facility has been reworded to better define the applicability of the standards.

The preamble to the proposed standard (38 FR 15406) urged all interested parties to submit factual data during the comment period to ensure that the standard for asphalt concrete plants would, upon promulgation, be consistent with the requirements of section 111 of the Act. A substantial amount of information on emission tests was submitted in response to this request. The information is summarized and discussed in Volume 3 of the background information document.

The proposed concentration standard was based on the conclusion that the best demonstrated systems of emission reduction, considering costs, are well designed, operated, and maintained baghouses or venturi scrubbers. The emission test data available at the time of proposal indicated that such systems could attain an emission level of 70 mg/Nm^3, or 0.031 gr/dscf. After considering comments on the proposed standard and new emission test data, a thorough eval-

ulation was made of the achievability of the proposed standard. As a result of this evaluation, the concentration standard was changed to 90 mg/dscm, or 0.04 gr/dscf.

With the exception of three cases, the acceptable data had shown that the proposed concentration standard, 0.031 gr/dscf, is achievable with a properly designed, installed, operated, and maintained baghouse or venturi scrubber. The three exceptions, two plants equipped with baghouses and one with a venturi scrubber, had emissions between 0.031 and 0.04 gr/dscf.

Some of the major comments received from the industry were (1) the proposed concentration standard of 0.031 gr/dscf cannot be attained either consistently or at all with currently available equipment; (2) the standard should be 0.06 gr/dscf; (3) the standard should allow higher emissions when heavy fuel oil is burned; (4) the type of aggregate used by a plant changes and affects the emissions; (5) EPA failed to consider the impact of the standard on mobile plants, continuous-mix plants, and drum-mixing plants; and (6) the EPA control cost estimates are too low. Responses to these comments and others are given in Appendix E to Volume 3 of the background information document. When considered as a whole, along with the new emission data, the comments justify revising the standard. The revision is merely a change in EPA's judgment about what emission limit is achievable using the best systems of emission reduction. The revision is in no way a change in what EPA considers to be the best systems of emission reduction which, taking into account the cost of achieving such reduction, have been adequately demonstrated; these are still considered to be well designed, operated, and maintained baghouses or venturi scrubbers.

In response to comments received on the proposed opacity standard, additional data were obtained on visible emissions from three well-controlled plants. The data are summarized in Volume 3 of the background information document. No visible emissions were observed from the control equipment on any of the plants. In addition, one plant showed no visible fugitive emissions. Inspection of the two plants having visible fugitive emissions, together with the fact that one plant had no visible emissions, shows that all of the fugitive emissions observed could have been prevented by proper design, operation, and maintenance of the asphalt plant and its control equipment. The data show no normal process variations that would cause visible emissions, either fugitive or from the control device, at a well-controlled plant.

As indicated above in the discussion on opacity, the opacity standards are set such that they are not more restrictive than the applicable concentration standard. In the case of asphalt concrete plants, it is the judgment of the Administrator that if a plant's emissions equal or exceed 20 percent opacity, the emissions will also clearly exceed the concentration standard of 90 mg/dscm (0.04 gr/dscf). Therefore, the promulgated standard of 20 percent opacity is not more restrictive than the concentration standard and no specific time exemptions are considered necessary.

An additional relief from the opacity standard is provided by the regulation promulgated on October 15, 1973 (38 FR 28564), which exempts from opacity standards any emissions generated during startups, shutdowns, or malfunctions. A general discussion of the purpose of opacity standards and the issues involved in setting them is included in Chapter 2, Volume 3, of the background information document.

Section 60.90, applicability and designation of affected facility, is changed from that proposed in order to clarify how and when the standards apply to asphalt concrete plants. The proposed regulation was interpreted by some commentators as requiring existing plants to meet the standards of performance for new sources when equipment was normally replaced or modernized. The proposed regulation specified certain equipment, e.g., transfer and storage systems, as affected facilities, and, because of regulatory language, this could have been interpreted to mean that a new conveyor system installed to replace a worn-out conveyor system on an existing plant was a new source as defined in section 111(a)(2) of the Act. The promulgated regulation specifies the asphalt concrete plant as the affected facility in order to avoid this unwanted interpretation. An existing asphalt concrete plant is subject to the promulgated standards of performance for new sources only if a physical change to the plant or change in the method of operating the plant causes an increase in the amount of air pollutants emitted. Routine maintenance, repair and replacement; relocation of a portable plant; change of aggregate; and transfer of ownership are not considered modifications which would require an existing plant to comply with the standard.

Industry's comments on the cost estimates pertinent to the proposed standards pointed out some errors and oversights. The cost estimates have been revised to include: (1) An increase in the investment cost for baghouses, (2) a change of credit for mineral filler from $9.00 to $3.40 per ton, and (3) an increase in the disposal costs. The changes increased the estimated investment cost of the control equipment by approximately 20 percent. The revised cost estimates are presented in Volume 3 of the background information document. It is concluded after evaluating the revised estimates that a baghouse designed with a 6-to-1 air-to-cloth ratio or a venturi scrubber with a pressure drop of at least 20 inches water gauge can be installed, operated, and maintained at a reasonable cost. It should be noted that the cost estimates were revised because the original estimates contained some errors and oversights, not because the concentration standard was changed

Petroleum Refineries

The promulgated standards for petroleum refineries limit emissions of sulfur dioxide from fuel gas combustion systems and limit emissions of particulate matter and carbon monoxide from fluid catalytic cracking unit catalyst regenerators.

Each of the comments received on the proposed standards was reviewed and evaluated. The Agency's responses to the comments received are included in Appendix E of Volume 3 of the background information document. The Agency's rationale for the promulgated standards for petroleum refineries is summarized below. A more detailed statement is presented in Volume 3 of the background information document.

The major differences between the promulgated standards and the proposed standards are:

1. The combustion of process upset gases in flare systems has been exempted.

2. Hydrogen sulfide in fuel gases combusted in any number of facilities may be monitored at one location if sampling at this location yields results representative of the hydrogen sulfide concentration in the fuel gas combusted in each facility.

3. The opacity standard for catalyst regenerators has been changed from the proposed level of less than 20 percent except for 3 minutes in any 1 hour to less than 30 percent except for 3 minutes in any 1 hour.

4. The standard for particulate matter has been changed from the proposed level of 50 mg/Nm^3 (0.022 gr/dscf) to 1.0 kilogram per 1,000 kilograms of coke burn-off in the catalyst regenerator (0.027 gr/dscf).

The two changes made to the proposed standard for fuel gas combustion systems do not represent any change in the Agency's original intent. It was evident from the comments received, however, that the intent of the regulation was not clear. Therefore, explicit provisions were incorporated into the promulgated standard to exempt the flaring of process upset gases and to permit monitoring at one location of the hydrogen sulfide content of fuel gases combusted in any number of combustion devices. Although hydrogen sulfide monitors are widely used by industry, the Agency has not evaluated the operating characteristics of such instruments. For this reason, calibration and zero specifications have been prescribed in only general terms. On the basis of evaluation programs currently underway, these requirements will be revised, or further guidance will be provided concerning the selection, operation and maintenance of such instruments.

Commentators suggested that small petroleum refineries be exempt from the standard for fuel gas combustion systems since compliance with the standard would impose a severe economic penalty on small refineries. This problem was considered during the development of the proposed standard. It was concluded, however, that the proposed standard would have little or no adverse economic impact on petroleum refineries. In light

of the comments received, the Agency reexamined this point with particular attention to the small refiner.

The details of the anlaysis are presented in Appendix C to Volume 3 of the background information document. The domestic petroleum industry is extremely complex and highly sophisticated. Thus, any analysis of the petroleum refining industry will of necessity be based on a number of simplifying assumptions. Although the assumptions in the economic impact statement appear reasonable, the statement should not be viewed as definitively identifying specific costs; rather it identifies a range of costs and approximate impact points. The analysis examines more than the economic impact of the standard for fuel gas combustion systems. It also examines the combined economic impact of this standard for fuel gas combustion systems, the standards for fluid catalytic cracking units, the water quality effluent guidelines being developed for petroleum refineries, and EPA's regulations requiring the reduction of lead in gasoline. Essentially, the economic impact of 'pollution control' is reviewed in light of the petroleum import license-fee program being administered by the Oil and Gas Office of the Department of the Interior (38 FR 9645 and 38 FR 16195).

This program is designed to encourage expansion and construction of U.S. petroleum refining capacity and expansion of U.S. crude oil production by imposing a fee or tariff on imported petroleum products and crude oil. Although this program is currently being phased into practice with the full impact not to be felt until mid-1975, the central feature of the program is to impose a fee of 21c per barrel above world price on imported crude oil and a fee of 63c per barrel above world price on imported petroleum products such as gasoline, fuel oils, and 'unfinished' or intermediate petroleum products.

Under the conditions currently existing in the United States, which are forecast to continue throughout the remainder of this decade and most of the next decade, and with domestic demand for crude oil and petroleum products far outstripping domestic supply and petroleum refining capacity, the import license-fee program will encourage domestic prices of crude oil and petroleum products to increase to world levels plus the fee or tariff. Thus, an incentive of 42¢ per barrel (63¢ per barrel minus 21¢ per barrel) is provided to domestic refiners by this program. In cases where 'independent' refiners continue to enjoy a captive supply of domestic crude oil, or where 'major' refiners engaged in the exploration and production of domestic crude are successful in supplying their refineries with domestic crude oil, this incentive will approach the full 63¢ per barrel fee imposed on imported petroleum products.

The analysis indicates that the incentive provided to the domestic petroleum refining industry by the import license-fee program is greater than the costs of pollution control requirements. The differences in control costs for the small refiner relative to the large refiner will still exist, but with the fee system in operation the small refiner will not be forced into a no-growth situation because of compliance with EPA requirements. Therefore small refineries are not exempt from the standards.

In response to comments received on the proposed opacity standard, additional data were obtained on visible emissions from four well-controlled catalyst regenerators. The data, which are summarized in Volume 3 of the background information document, indicate that 20 percent opacity is too restrictive for a well-controlled plant. As indicated above in the discussion on opacity, it is the Administrator's intent to set opacity standards such that they are not more restrictive than the applicable concentration or mass standard. In the case of catalyst regenerators, it is the judgment of the Administrator that if visible emissions exceed 30 percent opacity except for 3 minutes in any 1 hour, such emissions will also clearly exceed the standard of 1.0 kilogram of particulate matter per 1,000 kilograms of coke burn-off. Therefore, the promulgated standard of 30 percent except for 3 minutes in any 1 hour is judged to be not more restrictive than the mass standard of 1.0 kg/1,000 kg of coke burn-off.

An additional relief from the opacity standard is provided by the regulations promulgated on October 15, 1973 (38 FR 28564), which exempt from opacity standards any emissions generated during startups, shutdowns, or malfunctions. A general discussion of the purpose of opacity standards and the issues involved in setting them is included in Chapter 2 of Volume 3 of the background information document.

Commentators pointed out that the volume of gases discharged to the atmosphere from catalyst regenerators can vary significantly, depending upon the overall system used to control emissions of particulate matter and carbon monoxide. Consequently, the degree of control required to meet the proposed concentration standard (50 mg/Nm^3) for particulate matter depends upon the overall type of emission control system employed.

The various types of emission control systems utilized by catalyst regenerators and the alternative means of expressing an emission standard for particulate matter other than by an allowable concentration of particulate matter were evaluated. The alternative ways of expressing the standard were (1) specification of control efficiency, (2) limiting emissions based on a process weight restriction, and (3) limiting emissions on the basis of the size or capacity of a unit. Expressing the standard in terms of kilograms of particulate matter per 1,000 kilograms of coke burn-off was determined to be the best alternative.

Several of those who wrote to the Agency indicated that the proposed particulate matter standard for catalyst regenerators (50 mg/Nm^3) was too restrictive. To fully evaluate these comments, additional data on emissions from well-controlled units were obtained from industry and a control agency. This new information and the detailed rationale for the promulgated standard are presented in Volume 3 of the background information document.

This evaluation led to the conclusion that the allowable particulate matter emissions should be increased to provide for the unavoidable increase in emissions due to the deterioration of the cyclones within a catalyst regenerator. The revision reflects a change in the Agency's judgment on what emission limit is achievable using the best systems of emission reduction; it is not a change in what the Agency considers to be the best systems of emission reduction that have been adequately demonstrated.

STORAGE VESSELS FOR PETROLEUM LIQUIDS

The promulgated standard applies to storage vessels with capacities greater than 151,412 liters (40,000 gallons) that contain crude petroleum, condensate, or finished or intermediate products of a petroleum refinery. To reduce emissions of hydrocarbons to the atmosphere, a vapor recovery system or equivalent control is required if the stored liquid has a true vapor pressure, under storage conditions, greater than 570 millimeters of mercury (mm Hg); and a floating roof or equivalent control is required if the stored liquid's pressure is between 78 and 570 mm Hg, inclusive. Records must be kept of liquids stored, by date; of typical vapor pressure; and, in certain cases, of average monthly storage temperatures. The Administrator may require, in specific cases, that the liquid be sampled and true vapor pressure determined, but normally the maintenance of good records that are ready for inspection will be the requirement that owners and operators must meet in order to demonstrate compliance.

The definition of "storage vessel" is changed from the proposed form to specifically exclude high-pressure vessels, subsurface caverns, porous-rock reservoirs, and some underground tanks. As commentators pointed out, these types of storage are optimum for preventing the release of emissions to the atmosphere and need no additional control devices. The proposed definition of "petroleum liquids" was validly criticized as being too inclusive, and it is changed to specify what is included and what is excluded. The definition of vapor recovery system expresses the intent, in part, of such a system as "to prevent * * * emission." Some commentators felt that this could imply a requirement for 100 percent effectiveness. The definition is consistent with the wording found in many State and local regulations for storage of petroleum liquids—regulations that have been sensibly enforced and complied with. EPA recognizes that the effectiveness of such systems varies with climate and types and concentrations of vapors and deliberately avoided requiring a specific level of effectiveness. Control systems which are capable of providing an equivalent amount of con-

trol of hydrocarbon emissions may be used in lieu of the systems specified by the standard. An example of an equivalent control system is one which incinerates with an auxiliary fuel the hydrocarbon emissions from the storage tank before such emissions are released into the atmosphere.

The storage of crude oil and condensate at producing fields is specifically exempted from the standard. The proposed regulation had intended such an exemption by applying the standard only to storage vessels with capacities above 65,000 gallons. Industry representatives indicated that this action would exempt essentially all of the producing field storage, but later data showed that larger tanks are used in these locations. The specific exemption in the promulgated regulation better suits the intention. The standard now applies at capacities greater than 40,000 gallons, the size originally selected as being most consistent with existing State and local regulations before it was increased to exempt producing field storage. Producing field storage is exempt because the low level of emissions, the relatively small size of these tanks, and their commonly remote locations argue against justifying the switch from the bolted-construction, fixed-roof tanks in common use to the welded-construction, floating-roof tanks that would be required for new sources to comply with the standards.

The proposed standard required the use of conservation vents when petroleum liquids were stored at true vapor pressures less than 78 mm Hg. This requirement is deleted because, as commentators validly argued, certain stocks foul these vents, in cold weather the vents must be locked open or removed to prevent freezing, and the beneficial effects of such vents are minimal.

The monitoring and recordkeeping requirements are substantially reduced from those which were proposed. Over half of those who commented on this regulation argued that an unjustifiable burden was placed on owners and operators of remote tank farms, terminals, and marketing operations. EPA agrees. The basis for the proposed standard was the large, modern refinery which could have met the proposed requirements with little difficulty. The reduced requirements aid both enforcement officials and owners/operators by reducing paperwork without sacrificing the objectives of the regulation.

Some specific maintenance requirements were proposed but are deleted. Commentators pointed out that these requirements were not sufficiently explicit. A recent change to the General Provisions, subpart A, (see FEDERAL REGISTER of October 15, 1973, 38 FR 28564) requires that all affected facilities and emission control systems be operated and maintained in a manner consistent with good air pollution control practice for minimizing emissions. This provision will ensure the use of good maintenance practices for storage vessels, which was the intent of the proposed maintenance requirements.

SECONDARY LEAD SMELTERS AND REFINERIES

The promulgated standards limit emissions of particulate matter (1) from blast (cupola) and reverberatory furnaces to no more than 50 mg/dscm (0.022 gr/dscf) and to less than 20 percent opacity, and (2) from pot furnaces having charging capacities equal to or greater than 250 kilograms to less than 10 percent opacity.

These standards are the same as those proposed except that the 2-minutes-per-hour exemption is removed from both opacity standards. The general rationale for this change is presented above in the discussion of opacity. Two factors led to this change in the opacity standards: (1) The separately promulgated regulations that provide exemptions from the opacity standards during periods of startup, shutdown, and malfunction (see FEDERAL REGISTER of October 15, 1973, 38 FR 28564), and (2) the comments, reevaluation of data, and collection of new data and information which show that there is no basis for time exemptions in addition to those provided for startups, shutdowns, and malfunctions, and that the opacity standard is not more restrictive than the concentration standard.

Minor changes to the proposed version of the regulation have been made to clarify meanings and to exclude repetitive provisions and definitions which are now included in subpart A, General Provisions, and which are applicable to all new source performance standards.

SECONDARY BRASS AND BRONZE INGOT PRODUCTION PLANTS

The promulgated standards limit the emissions of particulate matter (1) from reverberatory furnaces having production capacities equal to or greater than 1,000 kg (2,205 lb) to no more than 50 mg/dscm (0.022 gr/dscf) and to less than 20 percent opacity, (2) from electric furnaces having capacities equal to or greater than 1,000 kg (2,205 lb) to less than 10 percent opacity, and (3) from blast (cupola) furnaces having capacities equal to or greater than 250 kg/hr (550 lb/hr) to less than 10 percent opacity.

These standards are the same as those proposed except that the opacity limit for emissions from the affected reverberatory furnaces is increased from less than 10 percent to less than 20 percent and the 2-minutes-per-hour exemption is removed from all three opacity standards. The general rationale for these changes is presented in the discussion of opacity above. The three factors which led to these changes are (1) the data and comments, summarized in Volume 3 of the background information document, which show, in the judgment of the Administrator, that the opacity standard proposed for reverberatory furnaces was too restrictive and that the promulgated opacity standard is not more restricted than the concentration standard, (2) the separately promulgated regulations which provide exemptions from opacity standards during periods of startup, shutdown, and malfunction (see FEDERAL REGISTER of October 15, 1973, 38 FR 28564), and (3) the comments, reevaluation of data, and collection of new data and information which show that there is no basis for additional time exemptions.

Minor changes to the proposed version of the regulation have been made to clarify meanings and to exclude repetitive provisions and definitions which are now included in subpart A, General Provisions, and which are applicable to all new source performance standards.

IRON AND STEEL PLANTS

The promulgated standards limit the emissions of particulate matter from basic oxygen process furnaces to no more than 50 mg/dscm (0.022 gr/dscf). This is the same concentration limit as was proposed. The opacity standard and the attendant monitoring requirement are not promulgated at this time. Sections of the regulation are reserved for the inclusion of these portions at a later date. Commentators pointed out the inappropriateness of the proposed opacity standard (10 percent opacity except for 2 minutes each hour) for this cyclic steelmaking process. The separate promulgation of regulations which provide exemptions from opacity standards during periods of startup, shutdown, and malfunction (see FEDERAL REGISTER of October 15, 1973, 38 FR 28564) add another dimension to the problem, and new data show variations in opacity for reasons not yet well enough identified.

The promulgated regulation represents no substantial change to that proposed. Some wording is changed to clarify meanings and, as discussed under General Provisions above, several provisions and definitions are deleted from this subpart and added to subpart A, which applies to all new source performance standards, to avoid repetition.

SEWAGE TREATMENT PLANTS

The promulgated standards for sludge incinerators at municipal sewage treatment plants limit particulate emissions to no more than 0.65 g/kg dry sludge input (1.30 lb/ton dry sludge input) and to less than 20 percent opacity. The proposed standards would have limited emissions to a concentration of 70 mg/Nm^3 (0.031 gr/dscf) and to less than 10 percent opacity except for 2 minutes in any 1 hour. The level of control required by the standard remains the same, but the units are changed from a concentration to a mass basis because the determination of combustion air as opposed to dilution air for these facilities is particularly difficult and could lead to unacceptable degrees of error. The section on test methods is revised in accordance with the change of units for the standard.

A section is added specifying instrumentation and sampling access points needed to determine sludge charging rate. Determination of this rate is necessary as a result of the change of units for the standard. Flow measuring devices with an accuracy of ± 5 percent must be installed to determine either the mass or volume of the sludge charged to the incinerator, and access to the sludge charged must be provided so a well-

mixed representative grab sample of the sludge can be obtained.

The general rationale for the change in the opacity standard is presented in the discussion of opacity above. The three factors which led to this change are (1) the data, summarized in Volume 3 of the background information document, which, in the judgment of the Administrator, show that the proposed opacity standard was too restrictive and that the promulgated standard is not more restrictive than the mass standard, (2) the separately promulgated regulations which provide exemptions from opacity standards during periods of startup, shutdown, and malfunction (see FEDERAL REGISTER of October 15, 1973, 38 FR 28564), and (3) reevaluation of data and collection of new data and information which show that there is no basis for additional time exemptions.

Minor changes to the proposed version of the regulation have been made to clarify meanings and to exclude repetitive provisions and definitions which are now included in subpart A, General Provisions, and are applicable to all new source performance standards.

TEST METHODS

Test Methods 10 and 11 as proposed contained typographical errors that are now corrected in both text and equations. Some wording is changed to clarify meanings and procedures as well.

In Method 10, which is for determination of CO emissions, the term "grab sampling" is changed to "continuous sampling" to prevent confusion. The Orsat analyzer is deleted from the list of analytical equipment because a less complex method of analysis was judged sufficiently sensitive. For clarification, a sentence is added to the section on reagents requiring calibration gases to be certified by the manufacturer. Temperature of the silica gel is changed from 177°C (350°F) to 175°C (347°F) to be consistent with the emphasis on metric units as the primary units. A technique for determining the CO_2 content of the gas has been added to both the continuous and integrated sampling procedures. This technique may be used rather than the technique described in Method 3. Use of the latter technique was required in the proposed Method 10.

Method 11, which is for determination of H_2S emissions, is modified to require five midget impingers rather than the proposed four. The fifth impinger contains hydrogen peroxide to remove sulfur dioxide as an interferant. A paragraph is added specifying the hydrogen peroxide solution to be used, and the procedure description is altered to include procedures specific to the fifth impinger. The term "iodine number flask" is changed to "iodine flask" to prevent confusion.

Dated: February 22, 1974.

RUSSELL E. TRAIN,
Administrator.

Part 60, Chapter I, Title 40, Code of Federal Regulations, is amended by revising subpart A, by adding new subparts I,J,K,L,M,N, and O, and by adding Methods 10 and 11 to the Appendix, as follows:

Subpart A—General Provisions

Sec.
60.2 Definitions.
60.3 Abbreviations.
60.4 Address.
60.6 Review of plans.
60.7 Notification and recordkeeping.
60.8 Performance tests.
60.12 Circumvention.

Subpart I—Standards of Performance for Asphalt Concrete Plants

60.90 Applicability and designation of affected facility.
60.91 Definitions.
60.92 Standard for particulate matter.
60.93 Test methods and procedures.

Subpart J—Standards of Performance for Petroleum Refineries

60.100 Applicability and designation of affected facility.
60.101 Definitions.
60.102 Standard for particulate matter.
60.103 Standard for carbon monoxide.
60.104 Standard for sulfur dioxide.
60.105 Emission monitoring.
60.106 Test methods and procedures.

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids

60.110 Applicability and designation of affected facility.
60.111 Definitions.
60.112 Standard for hydrocarbons.
60.113 Monitoring of operations.

Subpart L—Standards of Performance for Secondary Lead Smelters

60.120 Applicability and designation of affected facility.
60.121 Definitions.
60.122 Standard for particulate matter.
60.123 Test methods and procedures.

Subpart M—Standards of Performance for Secondary Brass and Bronze Ingot Production Plants

60.130 Applicability and designation of affected facility
60.131 Definitions.
60.132 Standard for particulate matter.
60.133 Test methods and procedures.

Subpart N—Standards of Performance for Iron and Steel Plants

60.140 Applicability and designation of affected facility.
60.141 Definitions.
60.142 Standard for particulate matter.
60.143 [Reserved]
60.144 Test methods and procedures.

Subpart O—Standards of Performance for Sewage Treatment Plants

60.150 Applicability and designation of affected facility.
60.151 Definitions.
60.152 Standard for particulate matter.
60.153 Monitoring of operations.
60.154 Test methods and procedures.

APPENDIX—TEST METHODS

Method 10—Determination of carbon monoxide emissions from stationary sources.
Method 11—Determination of hydrogen sulfide emissions from stationary sources.

AUTHORITY: Secs. 111, 114, Pub. L. 91-604 (42 U.S.C. 1857(c)(6) and (9)).

Subpart A—General Provisions

1. Section 60.2 is amended by revising paragraphs (i) and (l) and adding paragraphs (s), (t), (u), (v), and (w) as follows:

§ 60.2 Definitions.

* * * * *

(i) "Commenced" means, with respect to the definition of "new source" in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

* * * * *

(l) "Standard conditions" means a temperature of 20°C (68°F) and a pressure of 760 mm of Hg (29.92 in. of Hg)

* * * * *

(s) "Reference method" means any method of sampling and analyzing for an air pollutant as described in the appendix to this part.

(t) "Equivalent method" means any method of sampling and analyzing for an air pollutant which have been demonstrated to the Administartor's satisfaction to have a consistent and quantitatively known relationship to the reference method, under specified conditions.

(u) "Alternative method" means any method of sampling and analyzing for an air pollutant which is not a reference or equivalent method but which has been demonstrated to the Administrator's satisfaction to, in specific cases, produce results adequate for his determination of compliance.

(v) "Particulate matter" means any finely divided solid or liquid material, other than uncombined water, as measured by method 5 of the appendix.

(w) "Run" means the net period of time during which an emission sample is collected. Unless otherwise specified, a run may be either intermittent or continuous within the limits of good engineering practice.

2. Section 60.3 is revised to read as follows:

§ 60.3 Abbreviations.

The abbreviations used in this part have the following meanings:

A.S.T.M.—American Society for Testing and Materials
Btu—British thermal unit
°C—degree Celsius (centigrade)
cal—calorie
CdS—cadmium sulfide
cfm—cubic feet per minute
CO—carbon monoxide
CO_2—carbon dioxide
dscm—dry cubic meter(s) at standard conditions
dscf—dry cubic feet at standard conditions
eq—equivalents
°F—degree Fahrenheit
g—gram(s)
gal—gallon(s)
g eq—gram equivalents
gr—grain(s)

hr—hour(s)
HCl—hydrochloric acid
Hg—mercury
H_2O—water
H_2S—hydrogen sulfide
H_2SO_4—sulfuric acid
in.—inch(es)
°K—degree Kelvin
k—1,000
kg—kilogram(s)
l—liter(s)
lpm—liter(s) per minute
lb—pound(s)
m—meter(s)
meq—milliequivalent(s)
min—minute(s)
mg—milligram(s)
ml—milliliter(s)
mm—millimeter(s)
mol. wt.—molecular weight
mV—millivolt
N_2—nitrogen
nm—nanometer(s)—10^{-9} meter
NO—nitric oxide
NO_2—nitrogen dioxide
NO_x—nitrogen oxides
O_2—oxygen
ppb—parts per billion
ppm—parts per million
psia—pounds per square inch absolute
°R—degree Rankine
s—at standard conditions
sec—second
SO_2—sulfur dioxide
SO_3—sulfur trioxide
μg—microgram(s)—10^{-6} gram

3. Section 60.4 is revised to read as follows:

§ 60.4 Address.

All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate and addressed to the appropriate Regional Office of the Environmental Protection Agency, to the attention of the Director, Enforcement Division. The regional offices are as follows:

Region I (Connecticut, Maine, New Hampshire, Massachusetts, Rhode Island, Vermont), John F. Kennedy Federal Building, Boston, Massachusetts 02203.

Region II (New York, New Jersey, Puerto Rico, Virgin Islands), Federal Office Building, 26 Federal Plaza (Foley Square), New York, N.Y. 10007.

Region III (Delaware, District of Columbia, Pennsylvania, Maryland, Virginia, West Virginia), Curtis Building, Sixth and Walnut Streets, Philadelphia, Pennsylvania 19106.

Region IV (Alabama, Florida, Georgia, Mississippi, Kentucky, North Carolina, South Carolina, Tennessee), Suite 300, 1421 Peachtree Street, Atlanta, Georgia 30309.

Region V (Illinois, Indiana, Minnesota, Michigan, Ohio, Wisconsin), 1 North Wacker Drive, Chicago, Illinois 60606.

Region VI (Arkansas, Louisiana, New Mexico, Oklahoma, Texas), 1600 Patterson Street, Dallas, Texas 75201.

Region VII (Iowa, Kansas, Missouri, Nebraska), 1735 Baltimore Street, Kansas City, Missouri 64108.

Region VIII (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming), 916 Lincoln Towers, 1860 Lincoln Street, Denver, Colorado 80203.

Region IX (Arizona, California, Hawaii, Nevada, Guam, American Samoa), 100 California Street, San Francisco, California 94111.

Region X (Washington, Oregon, Idaho, Alaska), 1200 Sixth Avenue, Seattle, Washington 98101.

4. In § 60.6, paragraph (b) is revised to read as follows:

§ 60.6 Review of plans.

* * * * *

(b) (1) A separate request shall be submitted for each construction or modification project.

(2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any requipment to be used for measurement or control of emissions.

5. In § 60.7 paragraph (d) is added as follows:

§ 60.7 Notification and recordkeeping.

* * * * *

(d) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including monitoring and performance testing measurements, and all other reports and records required by all applicable subparts. Any such measurements, reports and records shall be retained for at least 2 years following the date of such measurements, reports, and records.

6. Section 60.8 is amended by revising paragraphs (b) and (f) and by deleting in paragraph (d) the number "10" after the word "Administrator" and substituting the number "30." The revised paragraphs (b) and (f) read as follows:

§ 60.8 Performance tests.

* * * * *

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, or (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

* * * * *

(f) Each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

7. A new § 60.12 is added to subpart A as follows:

§ 60.12 Circumvention.

No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

8. In Part 60, Subparts I, J, K, L, M, N, and O are added as follows:

Subpart I—Standards of Performance for Asphalt Concrete Plants

§ 60.90 Applicability and designation of affected facility.

The affected facility to which the provisions of this subpart apply is each asphalt concrete plant. For the purpose of this subpart, an asphalt concrete plant is comprised only of any combination of the following: Dryers; systems for screening, handling, storing, and weighing hot aggregate; systems for loading, transferring, and storing mineral filler; systems for mixing asphalt concrete; and the loading, transfer, and storage systems associated with emission control systems.

§ 60.91 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Asphalt concrete plant" means any facility, as described in § 60.90, used to manufacture asphalt concrete by heating and drying aggregate and mixing with asphalt cements.

§ 60.92 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any affected facility any gases which:

(1) Contain particulate matter in excess of 90 mg/dscm (0.04 gr/dscf).

(2) Exhibit 20 percent opacity, or greater. Where the presence of uncombined water is the only reason for failure to meet the requirements of this paragraph, such failure shall not be a violation of this section.

§ 60.93 Test methods and procedures.

(a) The reference methods appended to this part, except as provided for in § 60.8(b), shall be used to determine

compliance with the standards prescribed in § 60.92 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.9 dscm/hr (0.53 dscf/min) except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator.

Subpart J—Standards of Performance for Petroleum Refineries

§ 60.100 Applicability and designation of affected facility.

The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: Fluid catalytic cracking unit catalyst regenerators, fluid catalytic cracking unit incinerator-waste heat boilers, and fuel gas combustion devices.

§ 60.101 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A.

(a) "Petroleum refinery" means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives.

(b) "Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(c) "Process gas" means any gas generated by a petroleum refinery process unit, except fuel gas and process upset gas as defined in this section.

(d) "Fuel gas" means any gas which is generated by a petroleum refinery process unit and which is combusted, including any gaseous mixture of natural gas and fuel gas which is combusted.

(e) "Process upset gas" means any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

(f) "Refinery process unit" means any segment of the petroleum refinery in which a specific processing operation is conducted.

(g) "Fuel gas combustion device" means any equipment, such as process heaters, boilers and flares used to combust fuel gas, but does not include fluid coking unit and fluid catalytic cracking unit incinerator-waste heat boilers or facilities in which gases are combusted to produce sulfur or sulfuric acid.

(h) "Coke burn-off" means the coke removed from the surface of the fluid catalytic cracking unit catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in § 60.106.

§ 60.102 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator or from any fluid catalytic cracking unit incinerator-waste heat boiler:

(1) Particulate matter in excess of 1.0 kg/1000 kg (1.0 lb/1000 lb) of coke burn-off in the catalyst regenerator.

(2) Gases exhibiting 30 percent opacity or greater, except for 3 minutes in any 1 hour. Where the presence of uncombined water is the only reason for failure to meet the requirements of this subparagraph, such failure shall not be a violation of this section.

(b) In those instances in which auxiliary liquid or solid fossil fuels are burned in the fluid catalytic cracking unit incinerator-waste heat boiler, particular matter in excess of that permitted by paragraph (a)(1) of this section may be emitted to the atmosphere, except that the incremental rate of particulate emissions shall not exceed 0.18 g/million cal (0.10 lb/million Btu) of heat input attributable to such liquid or solid fuel.

§ 60.103 Standard for carbon monoxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from the fluid catalytic cracking unit catalyst regenerator any gases which contain carbon monoxide in excess of 0.050 percent by volume.

§ 60.104 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall burn in any fuel gas combustion device any fuel gas which contains H_2S in excess of 230 mg/dscm (0.10 gr/dscf), except as provided in paragraph (b) of this section. The combustion of process upset gas in a flare, or the combustion in a flare of process gas or fuel gas which is released to the flare as a result of relief valve leakage, is exempt from this paragraph.

(b) The owner or operator may elect to treat the gases resulting from the combustion of fuel gas in a manner which limits the release of SO_2 to the atmosphere if it is shown to the satisfaction of the Administrator that this prevents SO_2 emissions as effectively as compliance with the requirements of paragraph (a) of this section.

§ 60.105 Emission monitoring.

(a) The owner or operator of any petroleum refinery subject to the provisions of this subpart shall install, calibrate, maintain, and operate monitoring instruments as follows:

(1) A photoelectric or other type smoke detector and recorder to continuously monitor and record the opacity of gases discharged into the atmosphere from the fluid catalytic cracking unit catalyst regenerator.

(2) An instrument for continuously monitoring and recording the concentration of CO in gases discharged into the atmosphere from fluid catalytic cracking unit catalyst regenerators, except where the requirements of paragraph (a)(3) of this section are met.

(3) Instruments for continuously monitoring and recording firebox temperature and O_2 concentration in the exhaust gases from any incinerator-waste heat boiler which combusts the exhaust gases from a fluid catalytic cracking unit catalyst regenerator except where the requirements of paragraph (a)(2) of this section are met.

(4) An instrument for continuously monitoring and recording concentrations of H_2S in fuel gases burned in any fuel gas combustion device, except where the requirements of § 60.104(b) are met. Fuel gas combustion devices having a common source of fuel gas may be monitored at one location if sampling at this location produces results representative of the H_2S concentration in the fuel gas burned.

(5) An instrument for continuously monitoring and recording concentrations of SO_2 in the gases discharged into the atmosphere from the combustion of fuel gases except where the requirements of § 60.104(a) are met.

(b) Instruments and sampling systems installed and used pursuant to this section shall meet specifications prescribed by the Administrator and each instrument shall be calibrated in accordance with the method prescribed by the manufacturer of such instrument. The instruments shall be subjected to the manufacturer's recommended zero adjustment and calibration procedures at least once per 24-hour operating period unless the manufacturer specifies or recommends calibration at shorter intervals, in which case such specifications or recommendations shall be followed.

(c) The average coke burn-off rate (thousands of kilogram/hr) and hours of operation for any fluid catalytic cracking unit catalyst regenerator subject to § 60.102 or 60.103 shall be recorded daily.

(d) For any fluid catalytic cracking unit catalyst regenerator which is subject to § 60.102 and which utilizes an incinerator-waste heat boiler to combust the exhaust gases from the catalyst regenerator, the owner or operator shall record daily the rate of combustion of liquid or solid fossil fuels (liters/hr or kilograms/hr) and the hours of operation during which liquid or solid fossil fuels are combusted in the incinerator-waste heat boiler.

(e) For the purpose of reports pursuant to § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Opacity.* All hourly periods in which there are four or more 1-minute periods during which the average opacity

of the gases discharged into the atmosphere from any fluid catalytic cracking unit catalyst regenerator subject to § 60.102 exceeds 30 percent.

(2) *Carbon monoxide.* All hourly periods during which the average carbon monoxide concentration in the gases discharged into the atmosphere from any fluid catalytic cracking unit catalyst regenerator subject to § 60.103 exceeds 0.050 percent by volume; or any hourly period in which O_2 concentration and firebox temperature measurements indicate that the average concentration of CO in the gases discharged into the atmosphere exceeds 0.050 percent by volume for sources which combust the exhaust gases from any fluid catalytic cracking unit catalyst regenerator subject to § 60.103 in an incinerator-waste heat boiler and for which the owner or operator elects to monitor in accordance with § 60.105(a)(3).

(3) *Hydrogen sulfide.* All hourly periods during which the average hydrogen sulfide content of any fuel gas combusted in any fuel gas combustion device subject to § 60.104 exceeds 230 mg/dscm (0.10 gr/dscf) except where the requirements of § 60.104(b) are met.

(4) *Sulfur dioxide.* All hourly periods during which the average sulfur dioxide emissions discharged into the atmosphere from any fuel gas combustion device subject to § 60.104 exceed the level specified in § 60.104(b), except where the requirements of § 60.104(a) are met.

§ 60.106 Test methods and procedures.

(a) For the purpose of determining compliance with § 60.102(a)(1), the following reference methods and calculation procedures shall be used:

(1) For gases released to the atmosphere from the fluid catalytic cracking unit catalyst regenerator:

(i) Method 5 for the concentration of particulate matter and moisture content,

(ii) Method 1 for sample and velocity traverses, and

(iii) Method 2 for velocity and volumetric flow rate.

(2) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times may be approved by the Administrator when process variables or other factors preclude sampling for at least 60 minutes.

(3) For exhaust gases from the fluid catalytic cracking unit catalyst regenerator prior to the emission control system: the integrated sample techniques of Method 3 and Method 4 for gas analysis and moisture content, respectively; Method 1 for velocity traverses; and Method 2 for velocity and volumetric flow rate.

(4) Coke burn-off rate shall be determined by the following formula:

$$R_c = 0.2982\, Q_{RE}\,(\%CO_2 + \%CO) + 2.088\, Q_{RA} - 0.0994\, Q_{RE}\left(\frac{\%CO}{2} + \%CO_2 + \%O_2\right) \text{ (Metric Units)}$$

or

$$R_c = 0.0186\, Q_{RE}\,(\%CO_2 + \%CO) + 0.1303\, Q_{RA} - 0.0062\, Q_{RE}\left(\frac{\%CO}{2} + \%CO_2 + \%O_2\right) \text{ (English Units)}$$

where:

R_c = coke burn-off rate, kg/hr (English units: lb/hr).
0.2982 = metric units material balance factor divided by 100, kg-min/hr-m³.
0.0186 = English units material balance factor divided by 100, lb-min/hr-ft³.
Q_{RE} = fluid catalytic cracking unit catalyst regenerator exhaust gas flow rate before entering the emission control system, as determined by method 2, dscm/min (English units: dscf/min).
$\%CO_2$ = percent carbon dioxide by volume, dry basis, as determined by Method 3.
% CO = percent carbon monoxide by volume, dry basis, as determined by Method 3.
% O_2 = percent oxygen by volume, dry basis, as determined by Method 3.
2.088 = metric units material balance factor divided by 100, kg-min/hr-m³.
0.1303 = English units material balance factor divided by 100, lb-min/hr-ft³.
Q_{RA} = air rate to fluid catalytic cracking unit catalyst regenerator, as determined from fluid catalytic cracking unit control room instrumentation, dscm/min (English units: dscf/min).
0.0994 = metric units material balance factor divided by 100, kg-min/hr-m³.
0.0062 = English units material balance factor divided by 100, lb-min/hr-ft³.

(5) Particulate emissions shall be determined by the following equation:

$$R_E = (60\times10^{-6})\,Q_{RV}\,C_s \text{ (Metric Units)}$$

or

$$R_E = (8.57\times10^{-3})\,Q_{RV}\,C_s \text{ (English Units)}$$

where:

R_E = particulate emission rate, kg/hr (English units: lb/hr).
60×10^{-6} = metric units conversion factor, min-kg/hr-mg.
8.57×10^{-3} = English units conversion factor, min-lb/hr-gr.
Q_{RV} = volumetric flow rate of gases discharged into the atmosphere from the fluid catalytic cracking unit catalyst regenerator following the emission control system, as determined by Method 2, dscm/min (English units: dscf/min).
C_s = particulate emission concentration discharged into the atmosphere, as determined by Method 5, mg/dscm (English units: gr/dscf).

(6) For each run, emissions expressed in kg/1000 kg (English units: lb/1000 lb) of coke burn-off in the catalyst regenerator shall be determined by the following equation:

$$R_s = 1000\frac{R_E}{R_c} \text{ (Metric or English Units)}$$

where:

R_s = particulate emission rate, kg/1000 kg (English units lb/1000 lb) of coke burn-off in the fluid catalytic cracking unit catalyst regenerator.
1000 = conversion factor, kg to 1000 kg (English units: lb to 1000 lb).
R_E = particulate emission rate, kg/hr (English units: lb/hr).
R_c = coke burn-off rate, kg/hr (English units: lb/hr).

(7) In those instances in which auxiliary liquid or solid fossil fuels are burned in an incinerator-waste heat boiler, the rate of particulate matter emissions permitted under § 60.102(b) must be determined. Auxiliary fuel heat input, expressed in millions of cal/hr (English units: Millions of Btu/hr) shall be calculated for each run by fuel flow rate measurement and analysis of the liquid or solid auxiliary fossil fuels. For each run, the rate of particulate emissions permitted under § 60.102(b) shall be calculated from the following equation:

$$R_s = 1.0 + \frac{0.18\,H}{R_c} \text{ (Metric Units)}$$

or

$$R_s = 1.0 + \frac{0.10\,H}{R_c} \text{ (English Units)}$$

where:

R_s = allowable particulate emission rate, kg/1000 kg (English units: lb/1000 lb) of coke burn-off in the fluid catalytic cracking unit catalyst regenerator.
1.0 = emission standard, 1.0 kg/1000 kg (English units: 1.0 lb/1000 lb) of coke burn-off in the fluid catalytic cracking unit catalyst regenerator.
0.18 = metric units maximum allowable incremental rate of particulate emissions, g/million cal.
0.10 = English units maximum allowable incremental rate of particulate emissions, lb/million Btu.

H = heat input from solid or liquid fossil fuel, million cal/hr (English units: million Btu/hr).
R_c = coke burn-off rate, kg/hr (English units: lb/hr).

(b) For the purpose of determining compliance with § 60.103, the integrated sample technique of Method 10 shall be used. The sample shall be extracted at a rate proportional to the gas velocity at a sampling point near the centroid of the duct. The sampling time shall not be less than 60 minutes.

(c) For the purpose of determining compliance with § 60.104(a), Method 11 shall be used. When refinery fuel gas lines are operating at pressures substantially above atmospheric, the gases sampled must be introduced into the sampling train at approximately atmospheric pressure. This may be accomplished with a flow control valve. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line. The minimum sampling time shall be 10 minutes and the minimum sampling volume 0.01 dscm (0.35 dscf) for each sample. The arithmetic average of

two samples shall constitute one run. Samples shall be taken at approximately 1-hour intervals. For most fuel gases, sample times exceeding 20 minutes may result in depletion of the collecting solution, although fuel gases containing low concentrations of hydrogen sulfide may necessitate sampling for longer periods of time.

(d) Method 6 shall be used for determining concentration of SO_2 in determining compliance with § 60.104(b), except that H_2S concentration of the fuel gas may be determined instead. Method 1 shall be used for velocity traverses and Method 2 for determining velocity and volumetric flow rate. The sampling site for determining SO_2 concentration by Method 6 shall be the same as for determining volumetric flow rate by Method 2. The sampling point in the duct for determining SO_2 concentration by Method 6 shall be at the centroid of the cross section if the cross sectional area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 inches) if the cross sectional area is 5 m^2 or more and the centroid is more than one meter from the wall. The sample shall be extracted at a rate proportional to the gas velocity at the sampling point. The minimum sampling time shall be 10 minutes and the minimum sampling volume 0.01 dscm (0.35 dscf) for each sample. The arithmetic average of two samples shall constitute one run. Samples shall be taken at approximately 1-hour intervals.

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids

§ 60.110 Applicability and designation of affected facility.

(a) Except as provided in § 60.110(b), the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,412 liters (40,000 gallons).

(b) This subpart does not apply to storage vessels for the crude petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

§ 60.111 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Storage vessel" means any tank, reservoir, or container used for the storage of petroleum liquids, but does not include:

(1) Pressure vessels which are designed to operate in excess of 15 pounds per square inch gauge without emissions to the atmosphere except under emergency conditions,

(2) Subsurface caverns or porous rock reservoirs, or

(3) Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.

(b) "Petroleum liquids" means crude petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Number 2 through Number 6 fuel oils as specified in ASTM–D–396–69, gas turbine fuel oils Numbers 2–GT through 4–GT as specified in ASTM–D–2880–71, or diesel fuel oils Numbers 2–D and 4–D as specified in ASTM–D–975–68.

(c) "Petroleum refinery" means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives.

(d) "Crude petroleum" means a naturally occurring mixture which consists of hydrocarbons and/or sulfur, nitrogen and/or oxygen derivatives of hydrocarbons and which is a liquid at standard conditions.

(e) "Hydrocarbon" means any organic compound consisting predominantly of

(f) "Condensate" means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature and/or pressure and remains liquid at standard conditions.

(g) "Custody transfer" means the transfer of produced crude petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.

(h) "Drilling and production facility" means all drilling and servicing equipment, wells, flow lines, separators, equipment, gathering lines, and auxiliary nontransportation-related equipment used in the production of crude petroleum but does not include natural gasoline plants.

(i) "True vapor pressure" means the equilibrium partial pressure exerted by a petroleum liquid as determined in accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss from Floating Roof Tanks, 1962.

(j) "Floating roof" means a storage vessel cover consisting of a double deck, pontoon single deck, internal floating cover or covered floating roof, which rests upon and is supported by the petroleum liquid being contained, and is equipped with a closure seal or seals to close the space between the roof edge and tank wall.

(k) "Vapor recovery system" means a vapor gathering system capable of collecting all hydrocarbon vapors and gases discharged from the storage vessel and a vapor disposal system capable of processing such hydrocarbon vapors and gases so as to prevent their emission to the atmosphere.

(l) "Reid vapor pressure" is the absolute vapor pressure of volatile crude oil and volatile non-viscous petroleum liquids, except liquified petroleum gases, as determined by ASTM–D–323–58 (reapproved 1968).

§ 61.112 Standard for hydrocarbons.

(a) The owner or operator of any storage vessel to which this subpart applies shall store petroleum liquids as follows:

(1) If the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a floating roof, a vapor recovery system, or their equivalents.

(2) If the true vapor pressure of the petroleum liquid as stored is greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a vapor recovery system or its equivalent.

§ 60.113 Monitoring of operations.

(a) The owner or operator of any storage vessel to which this subpart applies shall for each such storage vessel maintain a file of each type of petroleum liquid stored, of the typical Reid vapor pressure of each type of petroleum liquid stored, and of the dates of storage. Dates on which the storage vessel is empty shall be shown.

(b) The owner or operator of any storage vessel to which this subpart applies shall for each such storage vessel determine and record the average monthly storage temperature and true vapor pressure of the petroleum liquid stored at such temperature if:

(1) The petroleum liquid has a true vapor pressure, as stored, greater than 26 mm Hg (0.5 psia) but less than 78 mm Hg (1.5 psia) and is stored in a storage vessel other than one equipped with a floating roof, a vapor recovery system or their equivalents; or

(2) The petroleum liquid has a true vapor pressure, as stored, greater than 470 mm Hg (9.1 psia) and is stored in a storage vessel other than one equipped with a vapor recovery system or its equivalent.

(c) The average monthly storage temperature is an arithmetic average calculated for each calendar month, or portion thereof if storage is for less than a month, from bulk liquid storage temperatures determined at least once every 7 days.

(d) The true vapor pressure shall be determined by the procedures in API Bulletin 2517. This procedure is dependent upon determination of the storage temperature and the Reid vapor pressure, which requires sampling of the petroleum liquids in the storage vessels. Unless the Administrator requires in specific cases that the stored petroleum liquid be sampled, the true vapor pressure may be determined by using the average monthly storage temperature and the typical Reid vapor pressure. For those liquids for which certified specifications limiting the Reid vapor pressure exist, that Reid vapor pressure may be used. For other liquids, supporting analytical data must be made available on request to the Administrator when typical Reid vapor pressure is used.

Subpart L—Standards of Performance for Secondary Lead Smelters

§ 60.120 Applicability and designation of affected facility.

The provisions of this subpart are applicable to the following affected facil-

ities in secondary lead smelters: Pot furnaces of more than 250 kg (550 lb) charging capacity, blast (cupola) furnaces, and reverberatory furnaces.

§ 60.121 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Reverberatory furnace" includes the following types of reverberatory furnaces: stationary, rotating, rocking, and tilting.

(b) "Secondary lead smelter" means any facility producing lead from a lead-bearing scrap material by smelting to the metallic form.

(c) "Lead" means elemental lead or allows in which the predominant component is lead.

§ 60.122 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from a blast (cupola) or reverberatory furnace any gases which:

(1) Contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any pot furnace any gases which exhibit 10 percent opacity or greater.

(c) Where the presence of uncombined water is the only reason for failure to meet the requirements of paragraphs (a) (2) or (b) of this section, such failure shall not be a violation of this section.

§ 60.123 Test methods and procedures.

(a) The reference methods appended to this part, except as provided for in § 60.8 (b), shall be used to determine compliance with the standards prescribed in § 60.122 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.9 dscm/hr (0.53 dscf/min) except that shorter sampling times, when necesitated by process variables or other factors, may be approved by the Administrator. Particulate sampling shall be conducted during representative periods of furnace operation, including charging and tapping.

Subpart M—Standards of Performance for Secondary Brass and Bronze Ingot Production Plants

§ 60.130 Applicability and designation of affected facility.

The provisions of this subpart are applicable to the following affected facilities in secondary brass or bronze ingot production plants: Reverberatory and electric furnaces of 1,000 kg (2,205 lb) or greater production capacity and blast (cupola) furnaces of 250 kg/hr (550 lb/hr) or greater production capacity.

§ 60.131 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Brass or bronze" means any metal alloy containing copper as its predominant constituent, and lesser amounts of zinc, tin, lead, or other metals.

(b) "Reverberatory furnace" includes the following types of reverberatory furnaces: Stationary, rotating, rocking, and tilting.

(c) "Electric furnace" means any furnace which uses electricity to produce over 50 percent of the heat required in the production of refined brass or bronze.

(d) "Blast furnace" means any furnace used to recover metal from slag.

§ 60.132 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from a reverberatory furnace any gases which:

(1) Contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any blast (cupola) or electric furnace any gases which exhibit 10 percent opacity or greater.

(c) Where the presence of uncombined water is the only reason for failure to meet the requirements of paragraphs (a) (2) or (b) of this section, such failure shall not be a violation of this section.

§ 60.133 Test methods and procedures.

(a) The reference methods appended to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.132 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content.

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling time for each run shall be at least 120 minutes and the sampling rate shall be at least 0.9 dscm/hr (0.53 dscf/min) except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator. Particulate matter sampling shall be conducted during representative periods of charging and refining, but not during pouring of the heat.

Subpart N—Standards of Performance for Iron and Steel Plants

§ 60.140 Applicability and designation of affected facility.

The affected facility to which the provisions of this subpart apply is each basic oxygen process furnace.

§ 60.141 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Basic oxygen process furnace" (BOPF) means any furnace producing steel by charging scrap steel, hot metal, and flux materials into a vessel and introducing a high volume of an oxygen-rich gas.

(b) "Steel production cycle" means the operations required to produce each batch of steel and includes the following major functions: Scrap charging, preheating (when used), hot metal charging, primary oxygen blowing, additional oxygen blowing (when used), and tapping.

§ 60.142 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any affected facility any gases which:

(1) Contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

(2) [Reserved.]

§ 60.143 [Reserved]

§ 60.144 Test methods and procedures.

(a) The reference methods appended to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.142 as follows:

(1) Method 5 for concentration of particulate matter and associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling for each run shall continue for an integral number of cycles with total duration of at least 60 minutes. The sampling rate shall be at least 0.9 dscm/hr (0.53 dscf/min) except that shorter sampling times,

when necessitated by process variables or other factors, may be approved by the Administrator. A cycle shall start at the beginning of either the scrap preheat or the oxygen blow and shall terminate immediately prior to tapping.

Subpart O—Standards of Performance for Sewage Treatment Plants

§ 60.150 Applicability and designation of affected facility.

The affected facility to which the provisions of this subpart apply is each incinerator which burns the sludge produced by municipal sewage treatment facilities.

§ 60.151 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

§ 60.152 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator of any sewage sludge incinerator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere of:

(1) Particulate matter at a rate in excess of 0.65 g/kg dry sludge input (1.30 lb/ton dry sludge input).

(2) Any gases which exihibit 20 percent opacity or greater. Where the presence of uncombined water is the only reason for failure to meet the requirements of this paragraph, such failure shall not be a violation of this section.

§ 60.153 Monitoring of operations.

(a) The owner or operator of any sludge incinerator subject to the provisions of this subpart shall:

(1) Install, calibrate, maintain, and operate a flow measuring device which can be used to determine either the mass or volume of sludge charged to the incinerator. The flow measuring device shall have an accuracy of ±5 percent over its operating range.

(2) Provide access to the sludge charged so that a well-mixed representative grab sample of the sludge can be obtained.

§ 60.154 Test Methods and Procedures.

(a) The reference methods appended to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.152 as follows:

(1) Method 5 for concentration of particulate matter and associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.015 dscm/min (0.53 dscf/min), except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) Dry sludge charging rate shall be determined as follows:

(1) Determine the mass (S_M) or volume (S_V) of sludge charged to the incinerator during each run using a flow measuring device meeting the requirements of § 60.153(a)(1). If total input during a run is measured by a flow measuring device, such readings shall be used. Otherwise, record the flow measuring device readings at 5-minute intervals during a run. Determine the quantity charged during each interval by averaging the flow rates at the beginning and end of the interval and then multiplying the average for each interval by the time for each interval. Then add the quantity for each interval to determine the total quantity charged during the entire run, (S_M) or (S_V).

(2) Collect samples of the sludge charged to the incinerator in non-porous collecting jars at the beginning of each run and at approximately 1-hour intervals thereafter until the test ends, and determine for each sample the dry sludge content (total solids residue) in accordance with "224 G. Method for Solid and Semisolid Samples," *Standard Methods for the Examination of Water and Wastewater*, Thirteenth Edition, American Public Health Association, Inc., New York, N.Y., 1971, pp. 539–41, except that:

(i) Evaporating dishes shall be ignited to at least 103°C rather than the 550°C specified in step 3(a)(1).

(ii) Determination of volatile residue, step 3(b) may be deleted.

(iii) The quantity of dry sludge per unit sludge charged shall be determined in terms of either R_{DV} (metric units: mg dry sludge/liter sludge charged or English units: lb/ft³) or R_{DM} (metric units: mg dry sludge/mg sludge charged or English units: lb/lb).

(3) Determine the quantity of dry sludge per unit sludge charged in terms of either R_{DV} or R_{DM}.

(i) If the volume of sludge charged is used:

$$S_D = (60 \times 10^{-3}) \frac{R_{DV} S_V}{T} \text{ (Metric Units)}$$

or

$$S_D = (8.021) \frac{R_{DV} S_V}{T} \text{ (English Units)}$$

where:

S_D = average dry sludge charging rate during the run, kg/hr (English units: lb/hr).
R_{DV} = average quantity of dry sludge per unit volume of sludge charged to the incinerator, mg/l (English units: lb/ft³).
S_V = sludge charged to the incinerator during the run, m³ (English units: gal).
T = duration of run, min (English units: min).
60×10^{-3} = metric units conversion factor, 1-kg-min/m³-mg-hr.
8.021 = English units conversion factor, ft³-min/gal-hr.

(ii) If the mass of sludge charged is used:

$$S_D = (50) \frac{R_{DM} S_M}{T} \text{ (Metric or English Units)}$$

where:

S_D = average dry sludge charging rate during the run, kg/hr (English units: lb/hr).
R_{DM} = average ratio of quantity of dry sludge to quantity of sludge charged to the incinerator, mg/mg (English units: lb/lb).
S_M = sludge charged during the run, kg (English units: lb).
T = duration of run, min (Metric or English units).
60 = conversion factor, min/hr (Metric or English units).

(d) Particulate emission rate shall be determined by:

$$c^s w = c^s Q^s \text{ (Metric or English Units)}$$

where:

$c^s w$ = particulate matter mass emissions, mg/hr (English units: lb/hr).
c^s = particulate matter concentration, mg/m³ (English units: lb/dscf).
Q^s = volumetric stack gas flow rate; dscm/hr (English units: dscf/hr). Q^s and c^s shall be determined using Methods 2 and 5, respectively.

(e) Compliance with § 60.152(a) shall be determined as follows:

$$C_{ds} = (10^{-3}) \frac{c_{sw}}{S_D} \text{ (Metric Units)}$$

or

$$C_{ds} = (2000) \frac{c_{sw}}{S_D} \text{ (English Units)}$$

where:

C_{ds} = particulate emission discharge, g/kg dry sludge (English units: lb/ton dry sludge).
10^{-3} = Metric conversion factor, g/mg.
2000 = English conversion factor, lb/ton.

9. Methods 10 and 11 are added to the appendix as follows:

METHOD 10—DETERMINATION OF CARBON MONOXIDE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and Applicability.*

1.1 *Principle.* An integrated or continuous gas sample is extracted from a sampling point and analyzed for carbon monoxide (CO) content using a Luft-type nondispersive infrared analyzer (NDIR) or equivalent.

1.2 *Applicability.* This method is applicable for the determination of carbon monoxide emissions from stationary sources only when specified by the test procedures for determining compliance with new source performance standards. The test procedure will indicate whether a continuous or an integrated sample is to be used.

2. *Range and sensitivity.*

2.1 *Range.* 0 to 1,000 ppm.

2.2 *Sensitivity.* Minimum detectable concentration is 20 ppm for a 0 to 1,000 ppm span.

3. *Interferences.* Any substance having a strong absorption of infrared energy will interfere to some extent. For example, discrimination ratios for water (H_2O) and carbon dioxide (CO_2) are 3.5 percent H_2O per 7 ppm CO and 10 percent CO_2 per 10 ppm CO, respectively, for devices measuring in the 1,500 to 3,000 ppm range. For devices meas-

uring in the 0 to 100 ppm range, interference ratios can be as high as 3.5 percent H_2O per 25 ppm CO and 10 percent CO_2 per 50 ppm CO. The use of silica gel and ascarite traps will alleviate the major interference problems. The measured gas volume must be corrected if these traps are used.

4. *Precision and accuracy.*

4.1 *Precision.* The precision of most NDIR analyzers is approximately ±2 percent of span.

4.2 *Accuracy.* The accuracy of most NDIR analyzers is approximately ±5 percent of span after calibration.

5. *Apparatus.*

5.1 *Continuous sample* (Figure 10–1).

5.1.1 *Probe.* Stainless steel or sheathed Pyrex[1] glass, equipped with a filter to remove particulate matter.

5.1.2 *Air-cooled condenser, or equivalent.* To remove any excess moisture.

5.2 *Integrated sample* (Figure 10–2).

5.2.1 *Probe.* Stainless steel or sheathed Pyrex glass, equipped with a filter to remove particulate matter.

5.2.2 *Air-cooled condenser or equivalent.* To remove any excess moisture.

5.2.3 *Valve.* Needle valve, or equivalent, to to adjust flow rate.

5.2.4 *Pump.* Leak-free diaphragm type, or equivalent, to transport gas.

5.2.5 *Rate meter.* Rotameter, or equivalent, to measure a flow range from 0 to 1.0 liter per min. (0.035 cfm).

5.2.6 *Flexible bag.* Tedlar, or equivalent, with a capacity of 60 to 90 liters (2 to 3 ft^3). Leak-test the bag in the laboratory before using by evacuating bag with a pump followed by a dry gas meter. When evacuation is complete, there should be no flow through the meter.

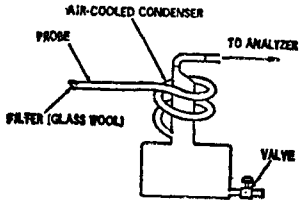


Figure 10-1. Continuous sampling train.

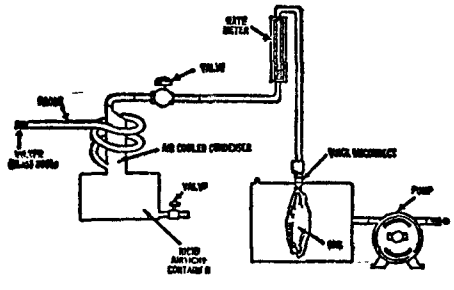


Figure 10-2. Integrated gas-sampling train.

5.2.7 *Pitot tube.* Type S, or equivalent, attached to the probe so that the sampling rate can be regulated proportional to the stack gas velocity when velocity is varying with the time or a sample traverse is conducted.

5.3 *Analysis* (Figure 10–3).

5.3.1 *Carbon monoxide analyzer.* Nondispersive infrared spectrometer, or equivalent. This instrument should be demonstrated, preferably by the manufacturer, to meet or exceed manufacturer's specifications and those described in this method.

5.3.2 *Drying tube.* To contain approximately 200 g of silica gel.

5.3.3 *Calibration gas.* Refer to paragraph 6.1.

5.3.4 *Filter.* As recommended by NDIR manufacturer.

5.3.5 *CO_2 removal tube.* To contain approximately 500 g of ascarite.

5.3.6 *Ice-water bath.* For ascarite and silica gel tubes.

5.3.7 *Valve.* Needle valve, or equivalent, to adjust flow rate

5.3.8 *Rate meter.* Rotameter or equivalent to measure gas flow rate of 0 to 1.0 liter per min. (0.035 cfm) through NDIR.

5.3.9 *Recorder (optional).* To provide permanent record of NDIR readings.

6. *Reagents.*

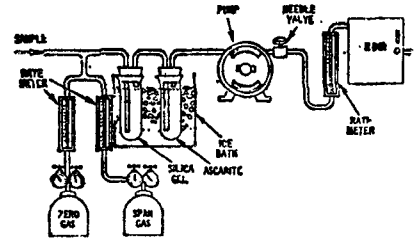


Figure 10-3. Analytical equipment.

6.1 *Calibration gases.* Known concentration of CO in nitrogen (N_2) for instrument span, prepurified grade of N_2 for zero, and two additional concentrations corresponding approximately to 60 percent and 30 percent span. The span concentration shall not exceed 1.5 times the applicable source performance standard. The calibration gases shall be certified by the manufacturer to be within ±2 percent of the specified concentration.

6.2 *Silica gel.* Indicating type, 6 to 16 mesh, dried at 175° C (347° F) for 2 hours.

6.3 *Ascarite.* Commercially available.

7. *Procedure.*

7.1 *Sampling.*

7.1.1 *Continuous sampling.* Set up the equipment as shown in Figure 10–1 making sure all connections are leak free. Place the probe in the stack at a sampling point and purge the sampling line. Connect the analyzer and begin drawing sample into the analyzer. Allow 5 minutes for the system to stabilize, then record the analyzer reading as required by the test procedure. (See ¶ 7.2 and 8). CO_2 content of the gas may be determined by using the Method 3 integrated sample procedure (36 FR 24886), or by weighing the ascarite CO_2 removal tube and computing CO_2 concentration from the gas volume sampled and the weight gain of the tube.

7.1.2 *Integrated sampling.* Evacuate the flexible bag. Set up the equipment as shown in Figure 10–2 with the bag disconnected. Place the probe in the stack and purge the sampling line. Connect the bag, making sure that all connections are leak free. Sample at a rate proportional to the stack velocity. CO_2 content of the gas may be determined by using the Method 3 integrated sample procedures (36 FR 24886), or by weighing the ascarite CO_2 removal tube and computing CO_2 concentration from the gas volume sampled and the weight gain of the tube.

7.2 *CO Analysis.* Assemble the apparatus as shown in Figure 10–3, calibrate the instrument, and perform other required operations as described in paragraph 8. Purge analyzer with N_2 prior to introduction of each sample. Direct the sample stream through the instrument for the test period, recording the readings. Check the zero and span again after the test to assure that any drift or malfunction is detected. Record the sample data on Table 10–1.

8. *Calibration.* Assemble the apparatus according to Figure 10–3. Generally an instrument requires a warm-up period before stability is obtained. Follow the manufacturer's instructions for specific procedure. Allow a minimum time of one hour for warm-up. During this time check the sample conditioning apparatus, i.e., filter, condenser, drying tube, and CO_2 removal tube, to ensure that each component is in good operating condition. Zero and calibrate the instrument according to the manufacturer's procedures using, respectively, nitrogen and the calibration gases.

TABLE 10–1.—*Field data*

Location _____ Comments:
Test _____
Date _____
Operator _____

Clock time	*Rotameter setting, liters per minute (cubic feet per minute)*

9. *Calculation—Concentration of carbon monoxide.* Calculate the concentration of carbon monoxide in the stack using equation 10–1.

$$C_{CO_{stack}} = C_{CO_{NDIR}}(1 - F_{CO_2}) \qquad \text{equation 10–1}$$

where:

$C_{CO_{stack}}$ = concentration of CO in stack, ppm by volume (dry basis).

$C_{CO_{NDIR}}$ = concentration of CO measured by NDIR analyzer, ppm by volume (dry basis).

F_{CO_2} = volume fraction of CO_2 in sample, i.e., percent CO_2 from Orsat analysis divided by 100.

[1] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

10. *Bibliography.*
10.1 McElroy, Frank, The Intertech NDIR–CO Analyzer, Presented at 11th Methods Conference on Air Pollution, University of California, Berkeley, Calif., April 1, 1970.
10.2 Jacobs, M. B., et al., Continuous Determination of Carbon Monoxide and Hydrocarbons in Air by a Modified Infrared Analyzer, J. Air Pollution Control Association, 9(2):110–114, August 1959.
10.3 MSA LIRA Infrared Gas and Liquid Analyzer Instruction Book, Mine Safety Appliances Co., Technical Products Division, Pittsburgh, Pa.
10.4 Models 215A, 315A, and 415A Infrared Analyzers, Beckman Instruments, Inc., Beckman Instructions 1635–B, Fullerton, Calif., October 1967.
10.5 Continuous CO Monitoring System, Model A5611, Intertech Corp., Princeton, N.J.
10.6 UNOR Infrared Gas Analyzers, Bendix Corp., Ronceverte, West Virginia.

ADDENDA

A. Performance Specifications for NDIR Carbon Monoxide Analyzers.

Range (minimum)	0–1000ppm.
Output (minimum)	0–10mV
Minimum detectable sensitivity	20 ppm.
Rise time, 90 percent (maximum)	30 seconds.
Fall time, 90 percent (maximum)	30 seconds.
Zero drift (maximum)	10% in 8 hours.
Span drift (maximum)	10% in 8 hours.
Precision (minimum)	± 2% of full scale.
Noise (maximum)	± 1% of full scale.
Linearity (maximum deviation)	2% of full scale.
Interference rejection ratio	CO_2—1000 to 1, H_2O—500 to 1.

B. *Definitions of Performance Specifications.*

Range—The minimum and maximum measurement limits.

Output—Electrical signal which is proportional to the measurement; intended for connection to readout or data processing devices. Usually expressed as millivolts or milliamps full scale at a given impedance.

Full scale—The maximum measuring limit for a given range.

Minimum detectable sensitivity—The smallest amount of input concentration that can be detected as the concentration approaches zero.

Accuracy—The degree of agreement between a measured value and the true value; usually expressed as ± percent of full scale.

Time to 90 percent response—The time interval from a step change in the input concentration at the instrument inlet to a reading of 90 percent of the ultimate recorded concentration.

Rise Time (90 percent)—The interval between initial response time and time to 90 percent response after a step increase in the inlet concentration.

Fall Time (90 percent)—The interval between initial response time and time to 90 percent response after a step decrease in the inlet concentration.

Zero Drift—The change in instrument output over a stated time period, usually 24 hours, of unadjusted continuous operation when the input concentration is zero; usually expressed as percent full scale.

Span Drift—The change in instrument output over a stated time period, usually 24 hours, of unadjusted continuous operation when the input concentration is a stated upscale value; usually expressed as percent full scale.

Precision—The degree of agreement between repeated measurements of the same concentration, expressed as the average deviation of the single results from the mean.

Noise—Spontaneous deviations from a mean output not caused by input concentration changes.

Linearity—The maximum deviation between an actual instrument reading and the reading predicted by a straight line drawn between upper and lower calibration points.

METHOD 11—DETERMINATION OF HYDROGEN SULFIDE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and applicability.*

1.1 *Principle.* Hydrogen sulfide (H_2S) is collected from the source in a series of midget impingers and reacted with alkaline cadmium hydroxide [$Cd(OH)_2$] to form cadmium sulfide (CdS). The precipitated CdS is then dissolved in hydrochloric acid and absorbed in a known volume of iodine solution. The iodine consumed is a measure of the H_2S content of the gas. An impinger containing hydrogen peroxide is included to remove SO_2 as an interfering species.

1.2 *Applicability.* This method is applicable for the determination of hydrogen sulfide emissions from stationary sources only when specified by the test procedures for determining compliance with the new source performance standards.

2. *Apparatus.*

2.1 *Sampling train.*

2.1.1 *Sampling line*—6- to 7-mm (¼-inch) Teflon [1] tubing to connect sampling train to sampling valve, with provisions for heating to prevent condensation. A pressure reducing valve prior to the Teflon sampling line may be required depending on sampling stream pressure.

2.1.2 *Impingers*—Five midget impingers, each with 30-ml capacity, or equivalent.

2.1.3 *Ice bath container*—To maintain absorbing solution at a constant temperature.

2.1.4 *Silica gel drying tube*—To protect pump and dry gas meter.

2.1.5 *Needle valve, or equivalent*—Stainless steel or other corrosion resistant material, to adjust gas flow rate.

2.1.6 *Pump*—Leak free, diaphragm type, or equivalent, to transport gas. (Not required if sampling stream under positive pressure.)

2.1.7 *Dry gas meter*—Sufficiently accurate to measure sample volume to within 1 percent.

2.1.8 *Rate meter*—Rotameter, or equivalent, to measure a flow rate of 0 to 3 liters per minute (0.1 ft^3/min).

2.1.9 *Graduated cylinder*—25 ml.

2.1.10 *Barometer*—To measure atmospheric pressure within ±2.5 mm (0.1 in.) Hg

2.2 *Sample Recovery.*

2.2.1 *Sample container*—500-ml glass-stoppered iodine flask.

2.2.2 *Pipette*—50-ml volumetric type.

2.2.3 *Beakers*—250 ml.

2.2.4 *Wash bottle*—Glass.

2.3 *Analysis.*

2.3.1 *Flask*—500-ml glass-stoppered iodine flask.

2.3.2 *Burette*—One 50 ml.

2.3.2 *Flask*—125-ml conical.

3. *Reagents.*

3.1 *Sampling.*

3.1.1 *Absorbing solution*—Cadmium hydroxide [$Cd(OH)_2$]—Mix 4.3 g cadmium sulfate hydrate (3 $CdSO_4 \cdot 8H_2O$) and 0.3 g of sodium hydroxide (NaOH) in 1 liter of distilled water (H_2O). Mix well.

Note: The cadmium hydroxide formed in this mixture will precipitate as a white suspension. Therefore, this solution must be thoroughly mixed before using to ensure an even distribution of the cadmium hydroxide.

3.1.2 *Hydrogen peroxide, 3 percent*—Dilute 30 percent hydrogen peroxide to 3 percent as needed. Prepare fresh daily;

3.2 *Sample recovery.*

3.2.1 *Hydrochloric acid solution (HCl), 10 percent by weight*—Mix 230 ml of concentrated HCl (specific gravity 1.19) and 770 ml of distilled H_2O.

3.2.2 *Iodine solution, 0.1 N*—Dissolve 24 g potassium iodide (KI) in 30 ml of distilled H_2O in a 1-liter graduated cylinder. Weigh 12.7 g of resublimed iodine (I_2) into a weighing bottle and add to the potassium iodide solution. Shake the mixture until the iodine is completely dissolved. Slowly dilute the solution to 1 liter with distilled H_2O, with swirling. Filter the solution, if cloudy, and store in a brown glass-stoppered bottle.

3.2.3 *Standard iodine solution, 0.01 N*—Dilute 100 ml of the 0.1 *N* iodine solution in a volumetric flask to 1 liter with distilled water.

Standardize daily as follows: Pipette 25 ml of the 0.01 *N* iodine solution into a 125-ml conical flask. Titrate with standard 0.01 *N* thiosulfate solution (see paragraph 3.3.2) until the solution is a light yellow. Add a few drops of the starch solution and continue titrating until the blue color just disappears. From the results of this titration, calculate the exact normality of the iodine solution (see paragraph 5.1).

3.2.4 *Distilled, deionized water.*

3.3 *Analysis.*

3.3.1 *Sodium thiosulfate solution, standard 0.1 N*—For each liter of solution, dissolve 24.8 g of sodium thiosulfate ($Na_2S_2O_3 \cdot 5H_2O$) in distilled water and add 0.01 g of anhydrous sodium carbonate (Na_2CO_3) and 0.4 ml of chloroform ($CHCl_3$) to stabilize. Mix thoroughly by shaking or by aerating with nitrogen for approximately 15 minutes, and store in a glass-stoppered glass bottle.

Standardize frequently as follows: Weigh into a 500-ml volumetric flask about 2 g of potassium dichromate ($K_2Cr_2O_7$) weighed to the nearest milligram and dilute to the 500-ml mark with distilled H_2O. Use dichromate which has been crystallized from distilled water and oven-dried at 182°C to 199°C (360°F to 390°F). Dissolve approximately 3 g of potassium iodide (KI) in 50 ml of distilled water in a glass-stoppered, 500-ml conical flask, then add 5 ml of 20-percent hydrochloric acid solution. Pipette 50 ml of the dichromate solution into this mixture. Gently swirl the solution once and allow it to stand in the dark for 5 minutes. Dilute the solution with 100 to 200 ml of distilled water, washing down the sides of the flask with part of the water. Swirl the solution slowly and titrate with the thoisulfate solution until the solution is light yellow. Add 4 ml of starch solution and continue with a slow titration with the thiosulfate until the bright blue color has disappeared and only the pale green color of the chromic ion remains. From this titration, calculate the exact normality of the sodium thiosulfate solution (see paragraph 5.2).

3.3.2 *Sodium thiosulfate solution, standard 0.01 N*—Pipette 100 ml of the standard 0.1 *N* thiosulfate solution into a volumetric flask and dilute to one liter with distilled water.

[1] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

3.3.3 *Starch indicator solution*—Suspend 10 g of soluble starch in 100 ml of distilled water and add 15 g of potassium hydroxide pellets. Stir until dissolved, dilute with 900 ml of distilled water, and let stand 1 hour. Neutralize the alkali with concentrated hydrochloric acid, using an indicator paper similar to Alkacid test ribbon, then add 2 ml of glacial acetic acid as a preservative.

Test for decomposition by titrating 4 ml of starch solution in 200 ml of distilled water with 0.01 *N* iodine solution. If more than 4 drops of the 0.01 *N* iodine solution are required to obtain the blue color, make up a fresh starch solution.

4. *Procedure.*

4.1 *Sampling.*

4.1.1 Assemble the sampling train as shown in Figure 11-1, connecting the five midget impingers in series. Place 15 ml of 3 percent hydrogen peroxide in the first impinger. Place 15 ml of the absorbing solution in each of the next three impingers, leaving the fifth dry. Place crushed ice around the impingers. Add more ice during the run to keep the temperature of the gases leaving the last impinger at about 20°C (70°F), or less.

4.1.2 Purge the connecting line between the sampling valve and the first impinger. Connect the sample line to the train. Record the initial reading on the dry gas meter as shown in Table 11-1.

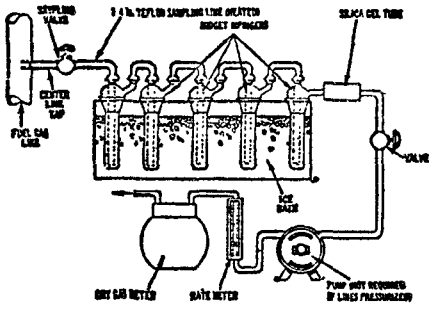


Figure 11-1. H_2S sampling train.

TABLE 11-1.—*Field data*

Location _____ Comments:

Test _____
Date _____
Operator _____
Barometric pressure_____

Clock time	Gas volume through meter (V_m), liters (cubic feet)	Rotameter setting, Lpm (cubic feet per minute)	Meter temperature, °C (°F)

4.1.3 Open the flow control valve and adjust the sampling rate to 1.13 liters per minute (0.04 cfm). Read the meter temperature and record on Table 11-1.

4.1.4 Continue sampling a minimum of 10 minutes. If the yellow color of cadmium sulfide is visible in the third impinger, analysis should confirm that the applicable standard has been exceeded. At the end of the sample time, close the flow control valve and read the final meter volume and temperature.

4.1.5 Disconnect the impinger train from the sampling line. Purge the train with clean ambient air for 15 minutes to ensure that all H_2S is removed from the hydrogen peroxide. Cap the open ends and move to the sample clean-up area.

4.2 *Sample recovery.*

4.2.1 Pipette 50 ml of 0.01 *N* iodine solution into a 250-ml beaker. Add 50 ml of 10 percent HCl to the solution. Mix well.

4.2.2 Discard the contents of the hydrogen peroxide impinger. Carefully transfer the contents of the remaining four impingers to a 500-ml iodine flask.

4.2.3 Rinse the four absorbing impingers and connecting glassware with three portions of the acidified iodine solution. Use the entire 100 ml of acidified iodine for this purpose. Immediately after pouring the acidified iodine into an impinger, stopper it and shake for a few moments before transferring the rinse to the iodine flask. Do not transfer any rinse portion from one impinger to another; transfer it directly to the iodine flask. Once acidified iodine solution has been poured into any glassware containing cadmium sulfide sample, the container must be tightly stoppered at all times except when adding more solution, and this must be done as quickly and carefully as possible. After adding any acidified iodine solution to the iodine flask, allow a few minutes for absorption of the H_2S into the iodine before adding any further rinses.

4.3.2 Titrate the blanks in the same manner as the samples.

4.2.4 Follow this rinse with two more rinses using distilled water. Add the distilled water rinses to the iodine flask. Stopper the flask and shake well. Allow about 30 minutes for absorption of the H_2S into the iodine, then complete the analysis titration.

Caution: Keep the iodine flask stoppered except when adding sample or titrant.

4.2.5 Prepare a blank in an iodine flask using 45 ml of the absorbing solution, 50 ml of 0.01 *N* iodine solution, and 50 ml of 10 percent HCl. Stopper the flask, shake well and analyze with the samples.

4.3 *Analysis.*

Note: This analysis titration should be conducted at the sampling location in order to prevent loss of iodine from the sample. Titration should never be made in direct sunlight.

4.3.1 Titrate the solution in the flask with 0.01 *N* sodium thiosulfate solution until the solution is light yellow. Add 4 ml of the starch indicator solution and continue titrating until the blue color just disappears.

5. *Calculations.*

5.1 *Normality of the standard iodine solution.*

$$N_I = \frac{N_T V_T}{V_I} \qquad \text{equation 11-1}$$

where:

N_I = normality of iodine, g-eq/liter.
V_I = volume of iodine used, ml.
N_T = normality of sodium thiosulfate, g-eq/liter.
V_T = volume of sodium thiosulfate used, ml.

5.2 *Normality of the standard thiosulfate sulution.*

$$N_T = 2.04 \frac{W}{V_T} \qquad \text{equation 11-2}$$

where:

W = weight of $K_2Cr_2O_7$ used, g.
V_T = volume of $Na_2S_2O_3$ used, ml.
N_T = normality of standard thiosulfate solution, g-eq/liter.
2.04 = conversion factor

$$= \frac{(6 \text{ eq } I_2/\text{mole } K_2Cr_2O_7)\ (1{,}000 \text{ ml/l})}{(294.2 \text{ g } K_2Cr_2O_7/\text{mole})\ (10 \text{ aliquot factor})}.$$

5.3 *Dry gas volume.* Correct the sample volume measured by the dry gas meter to standard conditions [21°C(70°F)] and 760 mm (29.92 inches) Hg] by using equation 11-3.

$$V_{m_{std}} = V_m \left(\frac{T_{std}}{T_m}\right)\left(\frac{P_{bar}}{P_{std}}\right) \qquad \text{equation 11-3}$$

where:

$V_{m_{std}}$ = volume at standard conditions of gas sample through the dry gas meter, standard liters (scf).
V_m = volume of gas sample through the dry gas meter (meter conditions), liters (cu. ft.).
T_{std} = absolute temperature at standard conditions, 294°K (530°R).
T_m = average dry gas meter temperature, °K (°R).
P_{bar} = barometric pressure at the orifice meter, mm Hg (in. Hg).
P_{std} = absolute pressure at standard conditions, 760 mm Hg (29.92 in. Hg).

5.4 *Concentration of H_2S.*—Calculate the concentration of H_2S in the gas stream at standard conditions using equation 11-4:

$$C_{H_2S} = \frac{K[(V_I N_I - V_T N_T)_{sample} - (V_I N_I - V_T N_T)_{blank}]}{V_{m_{std}}}$$

where (metric units):

C_{H_2S} = concentration of H_2S at standard conditions, mg/dscm
K = conversion factor = 17.0×10^3

$$= \frac{(34.07 \text{ g/mole } H_2S)(1{,}000 \text{ l/m}^3)(1{,}000 \text{ mg/g})}{(1{,}000 \text{ ml/l})(2H_2S \text{ eq/mole})}$$

V_I = volume of standard iodine solution, ml.
N_I = normality of standard iodine solution, g-eq/liter.
V_T = volume of standard sodium thiosulfate solution, ml.
N_T = normality of standard sodium thiosulfate solution, g-eq/liter.
$V_{m_{std}}$ = dry gas volume at standard conditions, liters.

where (English units):

$$K = 0.263 = \frac{17.0(15.43 \text{ gr/g})}{(1{,}000 \text{ l/m}^3)}$$

$V_{m_{std}}$ = scf.
C_{H_2S} = gr/dscf.

6. *References.*

6.1 Determination of Hydrogen Sulfide, Ammoniacal Cadmium Chloride Method, API Method 772-54. In: Manual on Disposal of Refinery Wastes, Vol. V: Sampling and Analysis of Waste Gases and Particulate Matter, American Petroleum Institute, Washington, D.C., 1954.

6.2 Tentative Method for Determination of Hydrogen Sulfide and Mercaptan Sulfur in Natural Gas, Natural Gas Processors Association, Tulsa, Oklahoma, NGPA Pubilcation No. 2265-65, 1965.

[FR Doc.74-4784 Filed 3-7-74;8:45 am]

FEDERAL REGISTER, VOL. 39, NO. 47—FRIDAY, MARCH 8, 1974

No. 47—Pt. II——3

6 RULES AND REGULATIONS

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Additions and Miscellaneous Amendments

Correction

In FR Doc. 74-4784 appearing at page 9307 as the Part II of the issue of Friday, March 8, 1974, make the following changes:

1. After the last line of § 60.111(e), insert "carbon and hydrogen".

2. In the second column on page 9317, what is now designated as "§ 61.112 Standard for hydrocarbons", should read "§ 60.112 Standard for hydrocarbons".

3. In the second line of § 60.121(c), the word "allows" should read "alloys".

4. In § 60.154:

a. In the last line of the formula in paragraph (c)(3)(i), "ft³" should read "ft³".

b. In the first line of the formula in paragraph (c)(3)(ii), "$S_D = (50)$" should read "$S_D = (60)$".

c. The formula in paragraph (d) should read as follows:

$$C_{da} = (10^{-3})\frac{C_{aw}}{S_D} \quad \text{(Metric Units)}$$

or

$$C_{da} = (2000)\frac{C_{aw}}{S_D} \quad \text{(English Units)}$$

where:

C_{da} = particulate emission discharge, g/kg dry sludge (English units: lb/ton dry sludge).
10^{-3} = Metric conversion factor, g/mg.
2000 = English conversion factor, lb/ton.

5. On page 9320, under paragraph 9. *Calculation—Concentration of carbon monoxide,* in the second equation under "where": "$^{C}CO_{NDIR}$" should read "$^{C}CO_{NDIR}$".

6. In the third column on page 9321, in the ninth line from the bottom of paragraph two under "3.3.1 *Sodium thiosulfate solution, standard 0.1 N*", "thoisulfate" should read "thiosulfate".

7. In the third column on page 9322, paragraph "4.3.2" should be transferred to appear below paragraph "4.3.1".

8. In paragraph 5.2 on page 9322, the last word "sulution" should read "solution".

9. In the formula on page 9323, put a closed parenthesis after "m³".

7 Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Additions and Miscellaneous Amendments

Correction

In FR Doc. 74-4784 appearing at page 9307 as the Part II of the issue of Friday, March 8, 1974, and corrected on page 13776 in the issue of Wednesday, April 17, 1974, on page 13776, "paragraph c." should read as follows:

c. The formula in paragraph (d) should read as follows:

(d) Particulate emission rate shall be determined by:

$c_{aw} = C_s Q_s$ (Metric or English Units)

where:

c_{aw} = Particulate matter mass emissions, mg/hr (English units: lb/hr).

c_s = Particulate matter concentration, mg/m³ (English units: lb/dscf).

Q_s = Volumetric stack gas flow rate, dscm/hr (English units: dscf/hr). Q_s and c_s shall be determined using Methods 2 and 5, respectively.

8 SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Miscellaneous Amendments

On December 23, 1971 (36 FR 24876), pursuant to section 111 of the Clean Air Act, as amended, the Administrator promulgated subpart A, General Provisions, and subparts D, E, F, G, and H which set forth standards of performance for new and modified facilities within five categories of stationary sources: (1) Fossil fuel-fired steam generators, (2) incinerators, (3) portland cement plants, (4) nitric acid plants, and (5) sulfuric acid plants. Corrections to these standards were published on July 26, 1972 (37 FR 14877), and on May 23, 1973 (38 FR 13562). On October 15, 1973 (38 FR 28564), the Administrator amended subpart A, General Provisions, by adding provisions to regulate compliance with standards of performance during startup, shutdown, and malfunction. On March 8, 1974 (39 FR 9308), the Administrator promulgated Subparts I, J, K, L, M, N, and O which set forth standards of performance for new and modified facilities within seven categories of stationary sources: (1) Asphalt concrete plants, (2) petroleum refineries, (3) storage vessels for petroleum liquids, (4) secondary lead smelters, (5) brass and bronze ingot production plants, (6) iron and steel plants, and (7) sewage treatment plants. In the same publication, the Administrator also promulgated amendments to subpart A, General Provisions. Corrections to these standards were published on April 17, 1974 (39 FR 13776).

Subpart D, E, F, G, and H are revised below to be consistent with the October 15, 1973, and March 8, 1974, amendments to subpart A. At the same time, changes in wording are made to clarify the regulations. These amendments do not modify the control requirements of the standards of performance. Also, to be consistent with the Administrator's policy of converting to the metric system, the standards of performance and other numerical entries, which were originally expressed in English units, are converted to metric units. Some of the numerical entries are rounded after conversion to metric units. It should be noted that the numerical entries in the reference methods in the appendix will be changed to metric units at a later date.

The new source performance standards promulgated March 8, 1974, applicable to petroleum storage vessels, included within their coverage storage vessels in the 40,000 to 65,000 gallon size range. The preamble to that publication discussed the fact that vessels of that size had not been included in the proposed rule, and set forth the reasons for their subsequent inclusion. However, through oversight, nothing was set forth in the regulations or preamble prescribing the effective date of the standards as to vessels within the 40,000 to 65,000 gallon range.

Section 111(a)(2) of the Act specifies that only a source for which construction is commenced after the date on which a pertinent new source standard is prescribed is subject to the standard unless the source was covered by the standard as proposed. In this case, the date of prescription or promulgation of the standard is clearly the operative date since there was no proposal date. Accordingly, § 60.1 is amended below to conform to the language of section 111(a)(2), and all persons are advised hereby that the provisions of Part 60

promulgated March 8, 1974, apply to storage vessels for petroleum liquids in the 40,000 to 65,000 gallon size range for which construction is commenced on or after that date.

On March 8, 1974, § 60.7(d) was added to require owners and operators to retain all recorded information, including monitoring and performance testing measurements, required by the regulations for at least 2 years after the date on which the information was recorded. This requirement is therefore deleted from Subparts D, E, F, G, and H specific to each new source in this group to avoid repetition. On March 8, 1974, the definitions of "particulate matter" and "run" were added to § 60.2. Therefore the definition of "particular matter" is removed from Subparts D, E, F, G, and H, and the term "repetition," used in these subparts in sections pertinent to performance tests, is changed to "run."

On October 15, 1973, § 60.8(c) was revised to require that performance tests be conducted under conditions specified by the Administrator based on representative performance of the affected facility. For that reason, the sections in Subparts D, E, F, G, and H specifying operating conditions to be met during performance tests are deleted.

Sections 60.40, 60.41(b) and 60.42(a)(1) are revised to clarify that the performance standards for steam generators do not apply when an existing unit changes to accommodate the use of combustible materials other than fossil fuel as defined in § 60.41(b).

Sections 60.41(a) and 60.51(a) are revised to eliminate the requirement that a unit have a "primary" purpose. This change is intended to prevent circumvention of a standard by simply defining the primary purpose of a unit as something other than steam production or reducing the volume of solid waste.

In § 60.46, A.S.T.M. Methods D2015–66 (Reapproved 1972), D240–64 (Reapproved 1973), and D1826–64 (Reapproved 1970) are specified for measuring heating value. Prior to this issue no method was specified for determining heating value.

The phrase "maximum 2-hour average" in the standards of performance prescribed in §§ 60.42, 60.52, 60.62, 60.72, and 60.82 is deleted. Concurrently, in §§ 60.46, 60.54, 60.64, and 60.85 the sampling time requirements for particulate matter and acid mist are changed from a minimum of 2 hours to a minimum of 60 minutes per run. The phrase "maximum 2-hour average" is not consonant with § 60.8(f) which requires that compliance be determined by averaging the results of three runs. Results from performance tests conducted at power plants and other sources have not shown any decrease in the accuracy or precision of 1-hour samples as compared with 2-hour samples, and therefore the extra hour required to sample for 2 hours is not justified. The time interval between samples for sulfur dioxide and nitrogen oxides was originally established so that one run would be completed at approximately the same time as the particulate matter run. To maintain this relationship, the sampling intervals specified in §§ 60.46 and 60.74 are shortened to be consistent with the 60-minute-per-run requirement.

The requirement prescribed in §§ 60.46, 60.64, 60.74 and 60.85 for using "suitable flow meters" for measuring fuel and product flow rates is deleted. Such meters may be used if available, but other suitable methods of determining the flow rate of fuel or product during the test period may also be used.

A procedure specifying how to allow for carbon dioxide absorption in a wet scrubber and a formula for correcting particulate matter emissions to a basis of 12 percent CO_2 are added to § 60.54.

In anticipation of adding other appendices, the present appendix to Part 60 is being retitled "Appendix A—Reference Methods." The definitions of "reference method" and "particulate matter" are amended to be consistent with this change.

In the regulations in Subpart K setting forth the performance standard for storage vessels for petroleum liquids, the definition of "crude petroleum" was to have been changed to be consistent with the definition of "petroleum" in Subpart J. This change was inadvertently not made in 39 FR 9308 and thus §§ 60.110 and 60.111 are amended by replacing the term "crude petroleum" with "petroleum."

The remaining structural and wording changes are made for purposes of clarification.

On June 29, 1973, the U.S. Court of Appeals for the District of Columbia remanded to EPA for further consideration the new source performance standards for portland cement plants. Portland Cement Association v. Ruckelshaus, 486 F.2d 375. On September 10, 1973, the same Court remanded to EPA for further consideration the new source performance standards for sulfuric acid plants and coal-fired steam electric generators. Essex Chemical Co. v. Ruckelshaus, 486 F.2d 427. The Agency has not completed its consideration with respect to the remanded standards. These amendments are not intended to constitute a response to the remands. At the time the Agency completes its consideration with respect to the remanded standards, it will publicly announce its decision and at that time if any revisions of the standards are deemed necessary or desirable, will make such revisions.

These actions are effective on June 14, 1974. The Agency finds good cause exists for not publishing these actions as a notice of proposed rulemaking and for making them effective immediately upon publication for the following reasons:

1. These actions are intended for clarification and for maintaining consistency throughout the regulations. They are not intended to alter the substantive content of the regulations.

2. Immediate effectiveness of the actions enables the sources involved to proceed with certainty in conducting their affairs, and persons wishing to seek judicial review of the actions may do so without delay.

(42 U.S.C. 1857 (c) (6) and (9))

Dated: June 10, 1974.

JOHN QUARLES,
Acting Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. Section 60.1 is revised to read as follows:

§ 60.1 Applicability.

The provisions of this part apply to the owner or operator of any stationary source which contains an affected facility the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to such facility.

2. Section 60.2 is amended by revising paragraphs (s) and (v) as follows:

§ 60.2 Definitions.

* * * * *

(s) "Reference method" means any method of sampling and analyzing for an air pollutant as described in Appendix A to this part.

* * * * *

(v) "Particulate matter" means any finely divided solid or liquid material, other than uncombined water, as measured by Method 5 of Appendix A to this part or an equivalent or alternative method.

* * * * *

3. Section 60.40 is revised to read as follows:

§ 60.40 Applicability and designation of affected facility.

The provisions of this subpart are applicable to each fossil fuel-fired steam generating unit of more than 63 million kcal per hour heat input (250 million Btu per hour), which is the affected facility. Any change to an existing fossil fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.

4. Section 60.41 is amended by deleting "primary" in paragraph (a), revising paragraph (b), and deleting paragraph (c). As amended, § 60.41 reads as follows:

§ 60.41 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, and in subpart A of this part.

(a) "Fossil fuel-fired steam generating unit" means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.

(b) "Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

5. Section 60.42 is revised to read as follows:

§ 60.42 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which:

(1) Contain particulate matter in excess of 0.18 g per million cal heat input (0.10 lb per million Btu) derived from fossil fuel.

(2) Exhibit greater than 20 percent opacity except that a maximum of 40 percent opacity shall be permissible for not more than 2 minutes in any hour. Where the presence of uncombined water is the only reason for failure to meet the requirements of this paragraph, such failure will not be a violation of this section.

6. Section 60.43 is revised to read as follows:

§ 60.43 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of:

(1) 1.4 g per million cal heat input (0.80 lb per million Btu) derived from liquid fossil fuel.

(2) 2.2 g per million cal heat input (1.2 lb per million Btu) derived from solid fossil fuel.

(b) When different fossil fuels are burned simultaneously in any combination, the applicable standard shall be determined by proration using the following formula:

$$\frac{y(1.4)+z(2.2)}{y+z}$$

where:

y is the percentage of total heat input derived from liquid fossil fuel, and

z is the percentage of total heat input derived from solid fossil fuel.

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

7. Section 60.44 is revised to read as follows:

§ 60.44 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:

(1) 0.36 g per million cal heat input (0.20 lb per million Btu) derived from gaseous fossil fuel.

(2) 0.54 g per million cal heat input (0.30 lb per million Btu) derived from liquid fossil fuel.

(3) 1.26 g per million cal heat input (0.70 lb per million Btu) derived from solid fossil fuel (except lignite).

(b) When different fossil fuels are burned simultaneously in any combination, the applicable standard shall be determined by proration. Compliance shall be determined by using the following formula:

$$\frac{x(0.36)+y(0.54)+z(1.26)}{x+y+z}$$

where:

x is the percentage of total heat input derived from gaseous fossil fuel,

y is the percentage of total heat input derived from liquid fossil fuel, and

z is the percentage of total heat input derived from solid fossil fuel (except lignite).

§ 60.45 [Amended]

8. Section 60.45 is amended by deleting and reserving paragraph (f).

9. Section 60.46 is revised to read as follows:

§ 60.46 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in §§ 60.42, 60.43, and 60.44 as follows:

(1) Method 1 for sample and velocity traverses;

(2) Method 2 for velocity and volumetric flow rate;

(3) Method 3 for gas analysis;

(4) Method 5 for the concentration of particulate matter and the associated moisture content;

(5) Method 6 for the concentration of SO_2; and

(6) Method 7 for the concentration of NO_x.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be 0.85 dscm (30.0 dscf) except that smaller sampling times or sample volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) For Methods 6 and 7, the sampling site shall be the same as that for determining volumetric flow rate. The sampling point in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft).

(d) For Method 6, the minimum sampling time shall be 20 minutes and the minimum sample volume shall be 0.02 dscm (0.71 dscf) except that smaller sampling times or sample volumes, when necessitated by process variables or other factors, may be approved by the Administrator. The sample shall be extracted at a rate proportional to the gas velocity at the sampling point. The arithmetic average of two samples shall constitute one run. Samples shall be taken at approximately 30-minute intervals.

(e) For Method 7, each run shall consist of at least four grab samples taken at approximately 15-minute intervals. The arithmetic mean of the samples shall constitute the run values.

(f) Heat input, expressed in cal per hr (Btu/hr), shall be determined during each testing period by multiplying the heating value of the fuel by the rate of fuel burned. Heating value shall be determined in accordance with A.S.T.M. Method D2015–66 (Reapproved 1972), D240–64 (Reapproved 1973), or D1826–64 (Reapproved 1970). The rate of fuel burned during each testing period shall be determined by suitable methods, and shall be confirmed by a material balance over the steam generation system.

(g) For each run, emissions expressed in g/million cal shall be determined by dividing the emission rate in g/hr by the heat input. The emission rate shall be determined by the equation $g/hr = Qs \times c$ where Qs=volumetric flow rate of the total effluent in dscm/hr as determined for each run in accordance with paragraph (a)(2) of this section.

(1) For particulate matter, c=particulate concentration in g/dscm, as determined in accordance with paragraph (a)(4) of this section.

(2) For SO_2, $c=SO_2$ concentration in g/dscm, as determined in accordance with paragraph (a)(5) of this section.

(3) For NO_x, $c=NO_x$ concentration in g/dscm, as determined in accordance with paragraph (a)(6) of this section.

10. Section 60.50 is revised to read as follows:

§ 60.50 Applicability and designation of affected facility.

The provisions of this subpart are applicable to each incinerator of more than 45 metric tons per day charging rate (50 tons/day), which is the affected facility.

§ 60.51 [Amended]

11. Section 60.51 is amended by striking the word "primary" in paragraph (a) and by deleting paragraph (d).

12. Section 60.52 is revised to read as follows:

§ 60.52 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this part shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of 0.18 g/dscm (0.08 gr/dscf) corrected to 12 percent CO_2.

13. Section 60.53 is revised to read as follows:

§ 60.53 Monitoring of operations.

(a) The owner or operator of any incinerator subject to the provisions of this part shall record the daily charging rates and hours of operation.

14. Section 60.54 is revised to read as follows:

§ 60.54 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.52 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis and calculation of excess air, using the integrated sample technique.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be 0.85 dscm (30.0 dscf) except that smaller sampling times or sample volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) If a wet scrubber is used, the gas analysis sample shall reflect flue gas conditions after the scrubber, allowing for carbon dioxide absorption by sampling the gas on the scrubber inlet and outlet sides according to either the procedure under paragraphs (c)(1) through (c)(5) of this section or the procedure under paragraphs (c)(1), (c)(2) and (c)(6) of this section as follows:

(1) The outlet sampling site shall be the same as for the particulate matter measurement. The inlet site shall be selected according to Method 1, or as specified by the Administrator.

(2) Randomly select 9 sampling points within the cross-section at both the inlet and outlet sampling sites. Use the first set of three for the first run, the second set for the second run, and the third set for the third run.

(3) Simultaneously with each particulate matter run, extract and analyze for CO_2 an integrated gas sample according to Method 3, traversing the three sample points and sampling at each point for equal increments of time. Conduct the runs at both inlet and outlet sampling sites.

(4) Measure the volumetric flow rate at the inlet during each particulate matter run according to Method 2, using the full number of traverse points. For the inlet make two full velocity traverses approximately one hour apart during each run and average the results. The outlet volumetric flow rate may be determined from the particulate matter run (Method 5).

(5) Calculate the adjusted CO_2 percentage using the following equation:

$$(\%\ CO_2)_{adj} = (\%\ CO_2)_{di}\ (Q_{di}/Q_{do})$$

where:

$(\%\ CO_2)_{adj}$ is the adjusted CO_2 percentage which removes the effect of CO_2 absorption and dilution air,

$(\%\ CO_2)_{di}$ is the percentage of CO_2 measured before the scrubber, dry basis,

Q_{di} is the volumetric flow rate before the scrubber, average of two runs, dscf/min (using Method 2), and

Q_{do} is the volumetric flow rate after the scrubber, dscf/min (using Methods 2 and 5)

(6) Alternatively, the following procedures may be substituted for the procedures under paragraphs (c) (3), (4), and (5) of this section:

(i) Simultaneously with each particulate matter run, extract and analyze for CO_2, O_2, and N_2 an integrated gas sample according to Method 3, traversing the three sample points and sampling for equal increments of time at each point. Conduct the runs at both the inlet and outlet sampling sites.

(ii) After completing the analysis of the gas sample, calculate the percentage of excess air (% EA) for both the inlet and outlet sampling sites using equation 3–1 in Appendix A to this part.

(iii) Calculate the adjusted CO_2 percentage using the following equation:

$$(\%\ CO_2)_{adj} = (\%\ CO_2)_{di}\left[\frac{100+(\%\ EA)_i}{100+(\%\ EA)_o}\right]$$

where:

$(\%\ CO_2)_{adj}$ is the adjusted outlet CO_2 percentage,

$(\%\ CO_2)_{di}$ is the percentage of CO_2 measured before the scrubber, dry basis,

$(\%\ EA)_i$ is the percentage of excess air at the inlet, and

$(\%\ EA)_o$ is the percentage of excess air at the outlet.

(d) Particulate matter emissions, expressed in g/dscm, shall be corrected to 12 percent CO_2 by using the following formula:

$$c_{12} = \frac{12c}{\%\ CO_2}$$

where:

c_{12} is the concentration of particulate matter corrected to 12 percent CO_2,

c is the concentration of particulate matter as measured by Method 5, and

$\%\ CO_2$ is the percentage of CO_2 as measured by Method 3, or when applicable, the adjusted outlet CO_2 percentage as determined by paragraph (c) of this section.

§ 60.61 [Amended]

15. Section 60.61 is amended by deleting paragraph (b).

16. Section 60.62 is revised to read as follows:

§ 60.62 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any kiln any gases which:

(1) Contain particulate matter in excess of 0.15 kg per metric ton of feed (dry basis) to the kiln (0.30 lb per ton).

(2) Exhibit greater than 10 percent opacity.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any clinker cooler any gases which:

(1) Contain particulate matter in excess of 0.050 kg per metric ton of feed (dry basis) to the kiln (0.10 lb per ton).

(2) Exhibit 10 percent opacity, or greater.

(c) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility other than the kiln and clinker cooler any gases which exhibit 10 percent opacity, or greater.

(d) Where the presence of uncombined water is the only reason for failure to meet the requirements of paragraphs (a)(2), (b)(2), and (c), such failure will not be a violation of this section.

17. Section 60.63 is revised to read as follows:

§ 60.63 Monitoring of operations.

(a) The owner or operator of any portland cement plant subject to the provisions of this part shall record the daily production rates and kiln feed rates.

18. Section 60.64 is revised to read as follows:

§ 60.64 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.62 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis.

(b) For Method 5, the minimum sampling time and minimum sample volume for each run, except when process variables or other factors justify otherwise to the satisfaction of the Administrator, shall be as follows:

(1) 60 minutes and 0.85 dscm (30.0 dscf) for the kiln.

(2) 60 minutes and 1.15 dscm (40.6 dscf) for the clinker cooler.

(c) Total kiln feed rate (except fuels), expressed in metric tons per hour on a dry basis, shall be determined during each testing period by suitable methods; and shall be confirmed by a material balance over the production system.

(d) For each run, particulate matter emissions, expressed in g/metric ton of kiln feed, shall be determined by dividing the emission rate in g/hr by the kiln feed rate. The emission rate shall be determined by the equation, $g/hr = Q_s \times c$, where Q_s=volumetric flow rate of the total effluent in dscm/hr as determined in accordance with paragraph (a)(3) of this section, and c=particulate concentration in g/dscm as determined in accordance with paragraph (a)(1) of this section.

19. Section 60.72 is revised to read as follows:

§ 60.72 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which:

(1) Contain nitrogen oxides, expressed as NO_2, in excess of 1.5 kg per metric ton of acid produced (3.0 lb per ton), the production being expressed as 100 percent nitric acid.

(2) Exhibit 10 percent opacity, or greater. Where the presence of uncombined water is the only reason for failure to meet the requirements of this paragraph, such failure will not be a violation of this section.

§ 60.73 [Amended]

20. Section 60.73 is amended by deleting and reserving paragraph (d).

21. Section 60.74 is revised to read as follows:

§ 60.74 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.72 as follows:

(1) Method 7 for the concentration of NO_x;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis.

(b) For Method 7, the sample site shall be selected according to Method 1 and the sampling point shall be the centroid of the stack or duct or at a point no closer to the walls than 1 m (3.28 ft). Each run shall consist of at least four grab samples taken at approximately 15-minutes intervals. The arithmetic mean of the samples shall constitute the run value. A velocity traverse shall be performed once per run.

(c) Acid production rate, expressed in metric tons per hour of 100 percent nitric acid, shall be determined during each testing period by suitable methods and shall be confirmed by a material balance over the production system.

(d) For each run, nitrogen oxides, expressed in g/metric ton of 100 percent nitric acid, shall be determined by dividing the emission rate in g/hr by the acid production rate. The emission rate shall be determined by the equation,

$$g/hr = Q_s \times c$$

where Q_s = volumetric flow rate of the effluent in dscm/hr, as determined in accordance with paragraph (a)(3) of this section, and $c = NO_x$ concentration in g/dscm, as determined in accordance with paragraph (a)(1) of this section.

22. Section 60.81 is amended by revising paragraph (b) as follows:

§ 60.81 Definitions.

* * * * *

(b) "Acid mist" means sulfuric acid mist, as measured by Method 8 of Appendix A to this part or an equivalent or alternative method.

23. Section 60.82 is revised to read as follows:

§ 60.82 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of 2 kg per metric ton of acid produced (4 lb per ton), the production being expressed as 100 percent H_2SO_4.

24. Section 60.83 is revised to read as follows:

§ 60.83 Standard for acid mist.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which:

(1) Contain acid mist, expressed as H_2SO_4, in excess of 0.075 kg per metric ton of acid produced (0.15 lb per ton), the production being expressed as 100 percent H_2SO_4.

(2) Exhibit 10 percent opacity, or greater. Where the presence of uncombined water is the only reason for failure to meet the requirements of this paragraph, such failure will not be a violation of this section.

§ 60.84 [Amended]

25. Section 60.84 is amended by deleting and reserving paragraph (d).

26. Section 60.85 is revised to read as follows:

§ 60.85 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in §§ 60.82 and 60.83 as follows:

(1) Method 8 for the concentrations of SO_2 and acid mist;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis.

(b) The moisture content can be considered to be zero. For Method 8 the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be 1.15 dscm (40.6 dscf) except that smaller sampling times or sample volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) Acid production rate, expressed in metric tons per hour of 100 percent H_2SO_4, shall be determined during each testing period by suitable methods and shall be confirmed by a material balance over the production system.

(d) Acid mist and sulfur dioxide emissions, expressed in g/metric ton of 100 percent H_2SO_4, shall be determined by dividing the emission rate in g/hr by the acid production rate. The emission rate shall be determined by the equation, $g/hr = Q_s \times c$, where Q_s = volumetric flow rate of the effluent in dscm/hr as determined in accordance with paragraph (a)(3) of this section, and c = acid mist and SO_2 concentrations in g/dscm as determined in accordance with paragraph (a)(1) of this section.

§ 60.110 [Amended]

27. Section 60.110(b) is amended by striking the words "the crude."

28. In § 60.111, paragraphs (b), (d), (g), and (h) are revised.

As amended § 60.111 reads as follows:

§ 60.111 Definitions.

* * * * *

(b) "Petroleum liquids" means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Number 2 through Number 6 fuel oils as specified in A.S.T.M. D396-69, gas turbine fuel oils Numbers 2-GT through 4-GT as specified in A.S.T.M. D2880-71, or diesel fuel oils Numbers 2-D and 4-D as specified in A.S.T.M. D975-68.

* * * * *

(d) "Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

* * * * *

(g) "Custody transfer" means the transfer of produced petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.

(h) "Drilling and production facility" means all drilling and servicing equipment, wells, flow lines, separators, equipment, gathering lines, and auxiliary nontransportation-related equipment used in the production of petroleum but does not include natural gasoline plants.

* * * * *

29. The appendix to Part 60 titled "Appendix—Test Methods" is retitled "Appendix A—Reference Methods."

[FR Doc.74-13633 Filed 6-13-74;8:45 am]

9

Title 40—Protection of the Environment

[FRL 285-2]

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

Region V Office: New Address

The Region V Office of EPA has been relocated. The new address is: EPA, Region V, Federal Building, 230 South Dearborn, Chicago, Illinois 60604. This change revises Region V's office address appearing in §§ 52.16, 60.4 and 61.04 of Title 40, Code of Federal Regulations.

Dated: October 21, 1974.

ROGER STRELOW,
Assistant Administrator for Air and Waste Management.

Parts 52, 60 and 61, Chapter I, Title 40 of the Code of Federal Regulations are amended as follows:

§§ 52.16, 60.4, 61.04 [Amended]

1. The address of the Region V office is revised to read:

Region V (Illinois, Indiana, Minnesota, Ohio, Wisconsin) Federal Building, 230 South Dearborn, Chicago, Illinois 60606.

[FR Doc.74-24919 Filed 10-24-74;8:45 am]

10

Title 40—Protection of the Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 291-6]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Opacity Provisions

On June 29, 1973, the United States Court of Appeals for the District of Columbia in "Portland Cement Association v. Ruckelshaus," 486 F. 2d 375 (1973) remanded to EPA the standard of performance for Portland cement plants (40 CFR 60.60 et seq.) promulgated by EPA under section 111 of the Clean Air Act. In the remand, the Court directed EPA to reconsider among other things the use of the opacity standards. EPA has prepared a response to the remand. Copies of this response are available from the Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711, Attn: Mr. Don R. Goodwin. In developing the response, EPA collected and evaluated a substantial amount of information which is summarized and referenced in the response. Copies of this information are available for inspection during normal office hours at EPA's Office of Public Affairs, 401 M Street SW., Washington, D.C. EPA determined that the Portland cement plant standards generally did not require revision but did not find that certain revisions are appropriate to the opacity provisions of the standards. The provisions promulgated herein include a revision to § 60.11, Compliance with Standards and Maintenance Requirements, a revision to the opacity standard for Portland cement plants, and revisions to Reference Method 9. The bases for the revisions are discussed in detail in the Agency's response to the remand. They are summarized below.

The revisions to § 60.11 include the modification of paragraph (b) and the addition of paragraph (e). Paragraph (b) has been revised to indicate that while Reference Method 9 remains the primary and accepted means for determining compliance with opacity standards in this part, EPA will accept as probative evidence in certain situations and under certain conditions the results of continuous monitoring by transmissometer to determine whether a violation has in fact occurred. The revision makes clear that even in such situations the results of opacity readings by Method 9 remain presumptively valid and correct.

The provisions in paragraph (e) provide a mechanism for an owner or operator to petition the Administrator to establish an opacity standard for an affected facility where such facility meets all applicable standards for which a performance test is conducted under § 60.8 but fails to meet an applicable opacity standard. This provision is intended primarily to apply to cases where a source installs a very large diameter stack which causes the opacity of the emissions to be

greater than if a stack of the diameter ordinarily used in the industry were installed. Although this situation is considered to be very unlikely to occur, this provision will accommodate such a situation. The provision could also apply to other situations where for any reason an affected facility could fail to meet opacity standards while meeting mass emission standards, although no such situations are expected to occur.

A revision to the opacity standard for Portland cement plants is promulgated herein. The revision changes the opacity limit for kilns from 10 percent to 20 percent. This revision is based on EPA's policy on opacity standards and the new emission data from Portland cement plants evaluated by EPA during its reconsideration. The preamble to the standards of performance which were promulgated on March 8, 1974 (39 FR 9308) sets forth EPA's policy on opacity standards: (1) Opacity limits are independent enforceable standards; (2) where opacity and mass/concentration standards are applicable to the same source, the mass/concentration standards are established at a level which will result in the design, installation, and operation of the best adequately demonstrated system of emission reduction (taking costs into account); and (3) the opacity standards are established at a level which will require proper operation and maintenance of such control systems. The new data indicate that increasing the opacity limits for kilns from 10 percent to 20 percent is justified, because such a standard will still require the design, installation, and operation of the best adequately demonstrated system of emission reduction (taking costs into account) while eliminating or minimizing the situations where it will be necessary to promulgate a new opacity standard under § 60.11(e).

In evaluating the accuracy of results from qualified observers following the procedures of Reference Method 9, EPA determined that some revisions to Reference Method 9 are consistently able to evaluation showed that observers trained and certified in accordance with the procedures prescribed under Reference Method 9 are consistently able to read opacity with errors not exceeding ± 7.5 percent based upon single sets of the average of 24 readings. The revisions to Reference Method 9 include the following:

1. An introductory section is added. This includes a discussion of the concept of visible emission reading and describes the effect of variable viewing conditions. Information is also presented concerning the accuracy of the method noting that the accuracy of the method must be taken into account when determining possible violations of applicable opacity standards.

2. Provisions are added which specify that the determination of opacity requires averaging 24 readings taken at 15-second intervals. The purpose for taking 24 readings is both to extend the averaging time over which the observations are made, and to take sufficient readings to insure acceptable accuracy.

3. More specific criteria concerning observer position with respect to the sun are added. Specifically, the sun must be within a 140° sector to the observer's back.

4. Criteria concerning an observer's position with respect to the plume are added. Specific guidance is also provided for reading emissions from rectangular emission points with large length to width ratios, and for reading emissions from multiple stacks. In each of these cases, emissions are to be read across the shortest path length.

5. Provisions are added to make clear that opacity of contaminated water or steam plumes is to be read at a point where water does not exist in condensed form. Two specific instructions are provided: One for the case where opacity can be observed prior to the formation of the condensed water plume, and one for the case where opacity is to be observed after the condensed water plume has dissipated.

6. Specifications are added for the smoke generator used for qualification of observers so that State or local air pollution control agencies may provide observer qualification training consistent with EPA training.

In developing this regulation we have taken into account the comments received in response to the September 11, 1974 (39 FR 35852) notice of proposed rulemaking which proposed among other things certain minor changes to Reference Method 9. This regulation represents the rulemaking with respect to the revisions to Method 9.

The determination of compliance with applicable opacity standards will be based on an average of 24 consecutive opacity readings taken at 15 second intervals. This approach is a satisfactory means of enforcing opacity standards in cases where the violation is a continuing one and time exceptions are not part of the applicable opacity standard. However, the opacity standards for steam electric generators in 40 CFR 60.42 and fluid catalytic cracking unit catalyst regenerators in 40 CFR 60.102 and numerous opacity standards in State implementation plans specify various time exceptions. Many State and local air pollution control agencies use a different approach in enforcing opacity standards than the six-minute average period specified in this revision to Method 9. EPA recognizes that certain types of opacity violations that are intermittent in nature require a different approach in applying the opacity standards than this revision to Method 9. It is EPA's intent to propose an additional revision to Method 9 specifying an alternative method to enforce opacity standards. It is our intent that this method specify a minimum number of readings that must be taken, such as a minimum of ten readings above the standard in any one hour period prior to citing a violation. EPA is in the process of analyzing available data and determining the error involved in reading opacity in this manner and will propose this revision to Method 9 as soon as this analysis is completed. The Agency solicits comments and recommendations on the need for this additional revision to Method 9 and would welcome any suggestions particularly from air pollution control agencies on how we might make Method 9 more responsive to the needs of these agencies.

These actions are effective on November 12, 1974. The Agency finds good cause exists for not publishing these actions as a notice of proposed rulemaking and for making them effective immediately upon publication for the following reasons:

(1) Only minor amendments are being made to the opacity standards which were remanded.

(2) The U.S. Court of Appeals for the District of Columbia instructed EPA to complete the remand proceeding with respect to the Portland cement plant standards by November 5, 1974.

(3) Because opacity standards are the subject of other litigation, it is necessary to reach a final determination with respect to the basic issues involving opacity at this time in order to properly respond to this issue with respect to such other litigation.

These regulations are issued under the authority of sections 111 and 114 of the Clean Air Act, as amended (42 U.S.C. 1857c-6 and 9).

Dated: November 1, 1974.

JOHN QUARLES,
Acting Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. Section 60.11 is amended by revising paragraph (b) and adding paragraph (e), reading as follows:

§ 60.11 Compliance with standards and maintenance requirements.

* * * * *

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Reference Method 9 in Appendix A of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in Appendix B of this part, has been properly maintained and (at the time of the alleged violation) calibrated, and that the resulting data have not been tampered with in any way.

* * * * *

(e) (1) An owner or operator of an affected facility may request the Admin-

istrator to determine opacity of emissions from the affected facility during the initial performance tests required by § 60.8.

(2) Upon receipt from such owner or operator of the written report of the results of the performance tests required by § 60.8, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with § 60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, he shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(3) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(4) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the FEDERAL REGISTER.

2. In § 60.62, paragraph (a)(2) is revised to read as follows:

§ 60.62 Standard for particulate matter.

(a) * * *

(2) Exhibit greater than 20 percent opacity.

* * * * *

3. Appendix A—Reference Methods is amended by revising Reference Method 9 as follows:

APPENDIX A—REFERENCE METHODS

* * * * *

METHOD 9—VISUAL DETERMINATION OF THE OPACITY OF EMISSIONS FROM STATIONARY SOURCES

Many stationary sources discharge visible emissions into the atmosphere; these emissions are usually in the shape of a plume. This method involves the determination of plume opacity by qualified observers. The method includes procedures for the training and certification of observers, and procedures to be used in the field for determination of plume opacity. The appearance of a plume as viewed by an observer depends upon a number of variables, some of which may be controllable and some of which may not be controllable in the field. Variables which can be controlled to an extent to which they no longer exert a significant influence upon plume appearance include: Angle of the observer with respect to the plume; angle of the observer with respect to the sun; point of observation of attached and detached steam plume; and angle of the observer with respect to a plume emitted from a rectangular stack with a large length to width ratio. The method includes specific criteria applicable to these variables.

Other variables which may not be controllable in the field are luminescence and color contrast between the plume and the background against which the plume is viewed. These variables exert an influence upon the appearance of a plume as viewed by an observer, and can affect the ability of the observer to accurately assign opacity values to the observed plume. Studies of the theory of plume opacity and field studies have demonstrated that a plume is most visible and presents the greatest apparent opacity when viewed against a contrasting background. It follows from this, and is confirmed by field trials, that the opacity of a plume, viewed under conditions where a contrasting background is present can be assigned with the greatest degree of accuracy. However, the potential for a positive error is also the greatest when a plume is viewed under such contrasting conditions. Under conditions presenting a less contrasting background, the apparent opacity of a plume is less and approaches zero as the color and luminescence contrast decrease toward zero. As a result, significant negative bias and negative errors can be made when a plume is viewed under less contrasting conditions. A negative bias decreases rather than increases the possibility that a plant operator will be cited for a violation of opacity standards due to observer error.

Studies have been undertaken to determine the magnitude of positive errors which can be made by qualified observers while reading plumes under contrasting conditions and using the procedures set forth in this method. The results of these studies (field trials) which involve a total of 769 sets of 25 readings each are as follows:

(1) For black plumes (133 sets at a smoke generator), 100 percent of the sets were read with a positive error[1] of less than 7.5 percent opacity; 99 percent were read with a positive error of less than 5 percent opacity.

(2) For white plumes (170 sets at a smoke generator, 168 sets at a coal-fired power plant, 298 sets at a sulfuric acid plant), 99 percent of the sets were read with a positive error of less than 7.5 percent opacity; 95 percent were read with a positive error of less than 5 percent opacity.

The positive observational error associated with an average of twenty-five readings is therefore established. The accuracy of the method must be taken into account when determining possible violations of applicable opacity standards.

1. *Principle and applicability.*

1.1 Principle. The opacity of emissions from stationary sources is determined visually by a qualified observer.

1.2 Applicability. This method is applicable for the determination of the opacity of emissions from stationary sources pursuant to § 60.11(b) and for qualifying observers for visually determining opacity of emissions.

2. *Procedures.* The observer qualified in accordance with paragraph 3 of this method shall use the following procedures for visually determining the opacity of emissions:

2.1 Position. The qualified observer shall stand at a distance sufficient to provide a clear view of the emissions with the sun oriented in the 140° sector to his back. Consistent with maintaining the above requirement, the observer shall, as much as possible, make his observations from a position such that his line of vision is approximately perpendicular to the plume direction, and when observing opacity of emissions from rectangular outlets (e.g. roof monitors, open baghouses, noncircular stacks), approximately perpendicular to the longer axis of the outlet. The observer's line of sight should not include more than one plume at a time when multiple stacks are involved, and in any case the observer should make his observations with his line of sight perpendicular to the longer axis of such a set of multiple stacks (e.g. stub stacks on baghouses).

2.2 Field records. The observer shall record the name of the plant, emission location, type facility, observer's name and affiliation, and the date on a field data sheet (Figure 9–1). The time, estimated distance to the emission location, approximate wind direction, estimated wind speed, description of the sky condition (presence and color of clouds), and plume background are recorded on a field data sheet at the time opacity readings are initiated and completed.

2.3 Observations. Opacity observations shall be made at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. The observer shall not look continuously at the plume, but instead shall observe the plume momentarily at 15-second intervals.

2.3.1 Attached steam plumes. When condensed water vapor is present within the plume as it emerges from the emission outlet, opacity observations shall be made beyond the point in the plume at which condensed water vapor is no longer visible. The observer shall record the approximate distance from the emission outlet to the point in the plume at which the observations are made.

2.3.2 Detached steam plume. When water vapor in the plume condenses and becomes visible at a distinct distance from the emission outlet, the opacity of emissions should be evaluated at the emission outlet prior to the condensation of water vapor and the formation of the steam plume.

2.4 Recording observations. Opacity observations shall be recorded to the nearest 5 percent at 15-second intervals on an observational record sheet. (See Figure 9–2 for an example.) A minimum of 24 observations shall be recorded. Each momentary observation recorded shall be deemed to represent the average opacity of emissions for a 15-second period.

2.5 Data Reduction. Opacity shall be determined as an average of 24 consecutive observations recorded at 15-second intervals. Divide the observations recorded on the record sheet into sets of 24 consecutive observations. A set is composed of any 24 consecutive observations. Sets need not be consecutive in time and in no case shall two sets overlap. For each set of 24 observations, calculate the average by summing the opacity of the 24 observations and dividing this sum by 24. If an applicable standard specifies an averaging time requiring more than 24 observations, calculate the average for all observations made during the specified time period. Record the average opacity on a record sheet. (See Figure 9–1 for an example.)

3. *Qualifications and testing.*

3.1 Certification requirements. To receive certification as a qualified observer, a candidate must be tested and demonstrate the ability to assign opacity readings in 5 percent increments to 25 different black plumes and 25 different white plumes, with an error

[1] For a set, positive error = average opacity determined by observers' 25 observations — average opacity determined from transmissometer's 25 recordings.

not to exceed 15 percent opacity on any one reading and an average error not to exceed 7.5 percent opacity in each category. Candidates shall be tested according to the procedures described in paragraph 3.2. Smoke generators used pursuant to paragraph 3.2 shall be equipped with a smoke meter which meets the requirements of paragraph 3.3.

The certification shall be valid for a period of 6 months, at which time the qualification procedure must be repeated by any observer in order to retain certification.

3.2 Certification procedure. The certification test consists of showing the candidate a complete run of 50 plumes—25 black plumes and 25 white plumes—generated by a smoke generator. Plumes within each set of 25 black and 25 white runs shall be presented in random order. The candidate assigns an opacity value to each plume and records his observation on a suitable form. At the completion of each run of 50 readings, the score of the candidate is determined. If a candidate fails to qualify, the complete run of 50 readings must be repeated in any retest. The smoke test may be administered as part of a smoke school or training program, and may be preceded by training or familiarization runs of the smoke generator during which candidates are shown black and white plumes of known opacity.

3.3 Smoke generator specifications. Any smoke generator used for the purposes of paragraph 3.2 shall be equipped with a smoke meter installed to measure opacity across the diameter of the smoke generator stack. The smoke meter output shall display in-stack opacity based upon a pathlength equal to the stack exit diameter, on a full 0 to 100 percent chart recorder scale. The smoke meter optical design and performance shall meet the specifications shown in Table 9–1. The smoke meter shall be calibrated as prescribed in paragraph 3.3.1 prior to the conduct of each smoke reading test. At the completion of each test, the zero and span drift shall be checked and if the drift exceeds ±1 percent opacity, the condition shall be corrected prior to conducting any subsequent test runs. The smoke meter shall be demonstrated, at the time of installation, to meet the specifications listed in Table 9–1. This demonstration shall be repeated following any subsequent repair or replacement of the photocell or associated electronic circuitry including the chart recorder or output meter, or every 6 months, whichever occurs first.

TABLE 9–1—SMOKE METER DESIGN AND PERFORMANCE SPECIFICATIONS

Parameter:	*Specification*
a. Light source	Incandescent lamp operated at nominal rated voltage.
b. Spectral response of photocell.	Photopic (daylight spectral response of the human eye—reference 4.3).
c. Angle of view	15° maximum total angle.
d. Angle of projection.	15° maximum total angle.
e. Calibration error.	±3% opacity, maximum.
f. Zero and span drift.	±1% opacity, 30 minutes.
g. Response time	≤5 seconds.

3.3.1 Calibration. The smoke meter is calibrated after allowing a minimum of 30 minutes warmup by alternately producing simulated opacity of 0 percent and 100 percent. When stable response at 0 percent or 100 percent is noted, the smoke meter is adjusted to produce an output of 0 percent or 100 percent, as appropriate. This calibration shall be repeated until stable 0 percent and 100 percent readings are produced without adjustment. Simulated 0 percent and 100 percent opacity values may be produced by alternately switching the power to the light source on and off while the smoke generator is not producing smoke.

3.3.2 Smoke meter evaluation. The smoke meter design and performance are to be evaluated as follows:

3.3.2.1 Light source. Verify from manufacturer's data and from voltage measurements made at the lamp, as installed, that the lamp is operated within ±5 percent of the nominal rated voltage.

3.3.2.2 Spectral response of photocell. Verify from manufacturer's data that the photocell has a photopic response; i.e., the spectral sensitivity of the cell shall closely approximate the standard spectral-luminosity curve for photopic vision which is referenced in (b) of Table 9–1.

3.3.2.3 Angle of view. Check construction geometry to ensure that the total angle of view of the smoke plume, as seen by the photocell, does not exceed 15°. The total angle of view may be calculated from: $\theta = 2 \tan^{-1} d/2L$, where θ = total angle of view; d = the sum of the photocell diameter + the diameter of the limiting aperture; and L = the distance from the photocell to the limiting aperture. The limiting aperture is the point in the path between the photocell and the smoke plume where the angle of view is most restricted. In smoke generator smoke meters this is normally an orifice plate.

3.3.2.4 Angle of projection. Check construction geometry to ensure that the total angle of projection of the lamp on the smoke plume does not exceed 15°. The total angle of projection may be calculated from: $\theta = 2 \tan^{-1} d/2L$, where θ = total angle of projection; d = the sum of the length of the lamp filament + the diameter of the limiting aperture; and L = the distance from the lamp to the limiting aperture.

3.3.2.5 Calibration error. Using neutral-density filters of known opacity, check the error between the actual response and the theoretical linear response of the smoke meter. This check is accomplished by first calibrating the smoke meter according to 3.3.1 and then inserting a series of three neutral-density filters of nominal opacity of 20, 50, and 75 percent in the smoke meter pathlength. Filters calibarted within ±2 percent shall be used. Care should be taken when inserting the filters to prevent stray light from affecting the meter. Make a total of five nonconsecutive readings for each filter. The maximum error on any one reading shall be 3 percent opacity.

3.3.2.6 Zero and span drift. Determine the zero and span drift by calibrating and operating the smoke generator in a normal manner over a 1-hour period. The drift is measured by checking the zero and span at the end of this period.

3.3.2.7 Response time. Determine the response time by producing the series of five simulated 0 percent and 100 percent opacity values and observing the time required to reach stable response. Opacity values of 0 percent and 100 percent may be simulated by alternately switching the power to the light source off and on while the smoke generator is not operating.

4. *References.*

4.1 Air Pollution Control District Rules and Regulations, Los Angeles County Air Pollution Control District, Regulation IV, Prohibitions, Rule 50.

4.2 Weisburd, Melvin I., Field Operations and Enforcement Manual for Air, U.S. Environmental Protection Agency, Research Triangle Park, N.C., APTD–1100, August 1972. pp. 4.1–4.36.

4.3 Condon, E. U., and Odishaw, H., Handbook of Physics, McGraw-Hill Co., N.Y., N.Y., 1958, Table 3.1, p. 6–52.

FIGURE 9-1
RECORD OF VISUAL DETERMINATION OF OPACITY

PAGE ___ of ___

COMPANY _____
LOCATION _____
TEST NUMBER _____
DATE _____
TYPE FACILITY _____
CONTROL DEVICE _____

HOURS OF OBSERVATION _____
OBSERVER _____
OBSERVER CERTIFICATION DATE _____
OBSERVER AFFILIATION _____
POINT OF EMISSIONS _____
HEIGHT OF DISCHARGE POINT _____

	Initial			Final
CLOCK TIME				
OBSERVER LOCATION Distance to Discharge				
Direction from Discharge				
Height of Observation Point				
BACKGROUND DESCRIPTION				
WEATHER CONDITIONS Wind Direction				
Wind Speed				
Ambient Temperature				
SKY CONDITIONS (clear, overcast, % clouds, etc.)				
PLUME DESCRIPTION Color				
Distance Visible				
OTHER INFORMATION				

SUMMARY OF AVERAGE OPACITY

Set Number	Time	Opacity	
	Start--End	Sum	Average

Readings ranged from ___ to ___ % opacity

The source was/was not in compliance with ___ at the time evaluation was made.

FIGURE 9-2 OBSERVATION RECORD PAGE ___ OF ___

COMPANY _____ OBSERVER _____
LOCATION _____ TYPE FACILITY _____
TEST NUMBER _____ POINT OF EMISSIONS _____
DATE _____

Hr.	Min.	Seconds 0	15	30	45	STEAM PLUME (check if applicable) Attached	Detached	COMMENTS
	0							
	1							
	2							
	3							
	4							
	5							
	6							
	7							
	8							
	9							
	10							
	11							
	12							
	13							
	14							
	15							
	16							
	17							
	18							
	19							
	20							
	21							
	22							
	23							
	24							
	25							
	26							
	27							
	28							
	29							

FIGURE 9-2 OBSERVATION RECORD (Continued) PAGE ___ OF ___

COMPANY _____ OBSERVER _____
LOCATION _____ TYPE FACILITY _____
TEST NUMBER _____ POINT OF EMISSIONS _____
DATE _____

Hr.	Min.	Seconds 0	15	30	45	STEAM PLUME (check if applicable) Attached	Detached	COMMENTS
	30							
	31							
	32							
	33							
	34							
	35							
	36							
	37							
	38							
	39							
	40							
	41							
	42							
	43							
	44							
	45							
	46							
	47							
	48							
	49							
	50							
	51							
	52							
	53							
	54							
	55							
	56							
	57							
	58							
	59							

[FR Doc.74-26150 Filed 11-11-74;8:45 am]

11

[FRL 306-3]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Coal Refuse

On December 23, 1971 (36 FR 24876), pursuant to section 111 of the Clean Air Act, as amended, the Administrator promulgated standards of performance for nitrogen oxides emissions from fossil fuel-fired steam generators of more than 63 million kcal per hour (250 million Btu per hour) heat input. The purpose of this amendment is to clarify the applicability of § 60.44 with regard to units burning significant amounts of coal refuse.

Coal refuse is the low-heat value, low-volatile, high-ash content waste separated from coal, usually at the mine site. It can prevent restoration of the land and produce acid water runoff. The low-heat value, high-ash characteristics of coal refuse preclude combustion except in cyclone furnaces with current technology, which because of the furnace design emit nitrogen oxides (NO_x) in quantities greater than that permitted by the standard of performance. Preliminary test results on an experimental unit and emission factor calculations indicate that NO_x emissions would be two to three times the standard of 1.26 g per million cal heat input (0.7 pound per million Btu). At the time of promulgation of § 60.44 in 1971, EPA was unaware of the possibility of burning coal refuse in combination with other fossil-fuels, and thus the standards of performance were not designed to apply to coal refuse combustion. However, since coal refuse is a fossil fuel, as defined under § 60.41(b), its combustion is included under the present standards of performance.

Upon learning of the possible problem of coal refuse combustion units meeting the standard of performance for NOx, the Agency investigated emission data, combustion characteristics of the material, and the possibility of burning it in other than cyclone furnaces before consideration was given to revising the standards of performance. The investigation indicated no reason to exempt coal refuse-fired units from the particulate matter or sulfur dioxide standards of performance, since achievement of these standards is not entirely dependent on furnace design. However, the investigation convinced the Agency that with current technology it is not possible to burn significant amounts of coal refuse and achieve the NOx standard of performance.

Combustion of coal refuse piles would reduce the volume of a solid waste that adversely affects the environment, would decrease the quantity of coal that needs to be mined, and would reduce acid water drainage as the piles are consumed. While NOx emissions from coal refuse-fired cyclone boilers are expected to be up to three times the standard of performance, the predicted maximum ground-level concentration increase for the only currently planned coal refuse-fired unit (173 MW) is only two micrograms NOx per cubic meter. This predicted increase would raise the total ground-level concentration around this source to only five micrograms NOx per cubic meter, which is well below the national ambient standard. For these reasons, § 60.44 is being amended to exempt steam generating units burning at least 25 percent (by weight) coal refuse from the NOx standard of performance. Such units must comply with the sulfur dioxide and particulate matter standards of performance.

Since this amendment is a clarification of the existing standard of performance and is expected to only apply to one source, no formal impact statement is required for this rulemaking, pursuant to section 1(b) of the "Procedures for the Voluntary Preparation of Environmental Impact Statements" (39 FR 37419).

This action is effective on January 18, 1975. The Agency finds good cause exists for not publishing this action as a notice of proposed rulemaking and for making it effective immediately upon publication because:

1. The action is a clarification of an existing regulation and is not intended to alter the overall substantive content of that regulation.

2. The action will affect only one planned source and is not ever expected to have wide applicability.

3. Immediate effectiveness of the action enables the source involved to proceed with certainty in conducting its affairs.

(42 U.S.C. 1847c-6, 9)

Dated: January 8, 1975.

JOHN QUARLES,
Acting Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. Section 60.41 is amended by adding paragraph (c) as follows:

60.41 Definitions.

* * * * *

(c) "Coal refuse" means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

2. Section 60.44 is amended by revising paragraphs (a)(3) and (b) as follows:

60.44 Standard for nitrogen oxides.

(a) * * *

(3) 1.26 g per million cal heat input (0.70 pound per million Btu) derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

(b) When different fossil fuels are burned simultaneously in any combination, the applicable standard shall be determined by proration using the following formula:

$$\frac{x\,(0.36)+y\,(0.54)+z\,(1.26)}{x+y+z}$$

where:

x is the percentage of total heat input derived from gaseous fossil fuel,
y is the percentage of total heat input derived from liquid fossil fuel, and
z is the percentage of total heat input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

When lignite or a solid fossil fuel containing 25 percent by weight, or more of coal refuse is burned in combination with gaseous, liquid or other solid fossil fuel, the standard for nitrogen oxides does not apply.

[FR Doc.75-1544 Filed 1-15-75;8:45 am]

12 [FRL 364-7]

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State of Washington

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of Washington on February 28, 1975, EPA is today amending 40 CFR 60.4 *Address*. A notice announcing this delegation was published on April 1, 1975 (40 FR 14632). The amended § 60.4 is set forth below.

The Administrator finds good cause for making this rulemaking effective immediately as the change is an administrative change and not one of substantive content. It imposes no additional substantive burdens on the parties affected.

This rulemaking is effective immediately, and is issued under the authority of section 111 of the Clean Air Act, as amended. 42 U.S.C. 1857c-6.

Dated: April 2, 1975.

ROGER STRELOW,
Assistant Administrator for Air and Waste Management.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

Subpart A—General Provisions

1. Section 60.4 is revised to read as follows:

§ 60.4 Address.

(a) All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate and addressed to the appropriate Regional Office of the Environmental Protection Agency, to the attention of the Director, Enforcement Division. The regional offices are as follows:

Region I (Connecticut, Maine, New Hampshire, Massachusetts, Rhode Island, Vermont), John F. Kennedy Federal Building, Boston, Massachusetts 02203.

Region II (New York, New Jersey, Puerto Rico, Virgin Islands), Federal Office Building, 26 Federal Plaza (Foley Square), New York, N.Y. 10007.

Region III (Delaware, District of Columbia, Pennsylvania, Maryland, Virginia, West Virginia), Curtis Building, Sixth and Walnut Streets, Philadelphia, Pennsylvania 19106.

Region IV (Alabama, Florida, Georgia, Mississippi, Kentucky, North Carolina, South Carolina, Tennessee), Suite 300, 1421 Peachtree Street, Atlanta, Georgia 30309.

Region V (Illinois, Indiana, Minnesota, Michigan, Ohio, Wisconsin), 1 North Wacker Drive, Chicago, Illinois 60606.

Region VI (Arkansas, Louisiana, New Mexico, Oklahoma, Texas), 1600 Patterson Street, Dallas, Texas 75201.

Region VII (Iowa, Kansas, Missouri, Nebraska), 1735 Baltimore Street, Kansas City, Missouri 63108.

Region VIII (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming), 196 Lincoln Towers, 1860 Lincoln Street, Denver, Colorado 80203.

Region IX (Arizona, California, Hawaii, Nevada, Guam, American Samoa), 100 California Street, San Francisco, California 94111.

Region X (Washington, Oregon, Idaho, Alaska), 1200 Sixth Avenue, Seattle, Washington 98101.

(b) Section 111(c) directs the Administrator to delegate to each State, when appropriate, the authority to implement and enforce standards of performance for new stationary sources located in such State. All information required to be submitted to EPA under paragraph (a) of this section, must also be submitted to the appropriate State Agency of any State to which this authority has been delegated (provided, that each specific delegation may except sources from a certain Federal or State reporting requirement). The appropriate mailing address for those States whose delegation request has been approved is as follows:

(A)-(Z) [reserved].
(AA)-(VV) [reserved].
WW-Washington: State of Washington, Department of Ecology, Olympia, Washington 98504.
(XX)-(ZZ) [reserved].
(AAA)-(DDD) [reserved].

[FR Doc.75-10797 Filed 4-24-75;8:45 am]

13 [FRL 389-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State of Idaho

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of Idaho on June 9, 1975, EPA is today amending 40 CFR 60.4, Address, to reflect this delegation. A notice announcing this delegation is published today at 40 FR 26728. The amended § 60.4, which adds the address of the State of Idaho, Department of Health and Welfare to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on June 9, 1975, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of section 111 of the Clean Air Act, as amended.

(42 U.S.C. 1857c-6.)

Dated: June 18, 1975.

ROBERT H. BAUM,
Acting Assistant Administrator for Enforcement.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (N) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)-(M) * * *

(N) State of Idaho, Department of Health and Welfare, Statehouse, Boise, Idaho, 83701.

* * * * *

[FR Doc.75-16583 Filed 6-24-75;8:45 am]

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 392-7]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Five Categories of Sources in the Phosphate Fertilizer Industry

On October 22, 1974 (39 FR 37602), under section 111 of the Clean Air Act, as amended, the Administrator proposed standards of performance for five new affected facilities within the phosphate fertilizer industry as follows: Wet-process phosphoric acid plants, superphosphoric acid plants, diammonium phosphate plants, triple superphosphate plants, and granular triple superphosphate storage facilities.

Interested parties participated in the rulemaking by sending comments to EPA. The Freedom of Information Center, Rm 202 West Tower, 401 M Street, SW., Washington, D.C. has copies of the comment letters received and a summary of the issues and Agency responses available for public inspection. In addition, copies of the issue summary and Agency responses may be obtained upon written request from the EPA Public Information Center (PM-215), 401 M Street, SW., Washington, D.C. 20460 (specify "Comment Summary: Phosphate Fertilizer Industry"). The comments have been considered and where determined by the Administrator to be appropriate, revisions have been made to the proposed standards, and the revised version of the standards of performance for five source categories within the phosphate fertilizer industry are herein promulgated. The principal revisions to the proposed standards and the Agency's responses to major comments are summarized below.

Definitions

The comment was made that the designation of affected facilities (§§ 60.200, 60.210, 60.220, 60.230, and 60.240) were confusing as written in the proposed regulations. As a result of the proposed wording, each component of an affected facility could have been considered a separate affected facility. Since this was not the intent, the affected facility designations have been reworded. In the new wording, the listing of components of an affected facility is intended for identification of those emission sources to which the standard for fluorides applies. Any sources not listed are not covered by the standard. Additionally, the definition of a "superphosphoric acid plant" has been changed to include facilities which concentrate wet-process phosphoric acid to 66 percent or greater P_2O_5 content instead of 60 percent as specified in the proposed regulations. This was the result of a comment stating that solvent extracted acids could be evaporated to greater than 60 percent P_2O_5 using conventional evaporators in the wet-process phosphoric acid plant. The revision clarifies the original intention of preventing certain wet-process phosphoric acid plants from being subject to the more restrictive standard for superphosphoric acid plants.

One commentator was concerned that a loose interpretation of the definition of the affected facility for diammonium phosphate plants might result in certain liquid fertilizer plants becoming subject to the standards. Therefore, the word "granular" has been inserted before "diammonium phosphate plant" in the appropriate places in subpart V to clarify the intended meaning.

Under the standards for triple superphosphate plants in § 60.231(b), the term "by weight" has been added to the definition of "run-of-pile triple superphosphate." Apparently it was not clear as to whether "25 percent of which (when not caked) will pass through a 16 mesh screen" referred to percent by weight or by particle count.

Opacity Standards

Many commentators challenged the proposed opacity standards on the grounds that EPA had shown no correlation between fluoride emissions and plume opacity, and that no data were presented which showed that a violation of the proposed opacity standard would indicate simultaneous violation of the proposed fluoride standard. For the opacity standard to be used as an enforcement tool to indicate possible violation of the fluoride standard, such a correlation must be established. The Agency has reevaluated the opacity test data and determined that the correlation is insufficient to support a standard. Therefore, standards for visible emissions for diammonium phosphate plants, triple superphosphate plants, and granular triple superphosphate storage facilities have been deleted. This action, however, is not meant to set a precedent regarding promulgation of visible emission standards. The situation which necessitates this decision relates only to fluoride emissions. In the future, the Agency will continue to set opacity standards for affected facilities where such standards are desirable and warranted based on test data.

In place of the opacity standard, a provision has been added which requires an owner or operator to monitor the total pressure drop across an affected facility's scrubbing system. This requirement will provide an affected facility's scrubbing system. This requirement will provide for a record of the operating conditions of the control system, and will serve as an effective method for monitoring compliance with the fluoride standards.

Reference Methods 13A and 13B

Reference Methods 13A and 13B, which prescribed testing and analysis procedures for fluoride emissions, were originally proposed along with standards of performance for the primary aluminum industry (39 FR 37730). However, these methods have been included with the standards of performance for the phosphate fertilizer industry and the the fertilizer standards are being promulgated before the primary aluminum standards. Comments were received from the phosphate fertilizer industry and the primary aluminum industry as the methods are applicable to both industries. The majority of the comments discussed possible changes to procedures and to equipment specifications. As a result of these comments some minor changes were made. Additionally, it has been determined that acetone causes a positive interference in the analytical procedures. Although the bases for the standard are not affected, the acetone wash has been deleted in both methods to prevent potential errors. Reference Method 13A has been revised to restrict the distillation procedure (Section 7.3.4) to 175°C instead of the proposed 180°C in order to prevent positive interferences introduced by sulfuric acid carryover in the distillate at the higher temperatures. Some commentators expressed a desire to replace the methods with totally different methods of analysis. They felt they should not be restricted to using only those methods published by the Agency. However, in response to these comments, an equivalent or alternative method may be used after approval by the Administrator according to the provisions of § 60.8(b) of the regulations (as revised in 39 FR 9308).

Fluoride Control

Comments were received which questioned the need for Federal fluoride control because fluoride emissions are localized and ambient fluoride concentrations are very low. As discussed in the preamble to the proposed regulations, fluoride was the only pollutant other than the criteria pollutants, specifically named as requiring Federal action in the March 1970 "Report of the Secretary of Health, Education, and Welfare to the United States (91st) Congress." The report concluded that "inorganic fluorides are highly irritant and toxic gases" which, even in low ambient concentrations, have adverse effects on plants and animals. The United States Senate Committee on Public Works in its report on the Clean Air Amendments of 1970 (Senate Report No. 91-1196, September 17, 1970, page 9) included fluorides on a list of contaminants which have broad national impact and require Federal action.

One commentator questioned EPA's use of section 111 of the Clean Air Act, as amended, as a means of controlling fluoride air pollution, Again, as was mentioned in the preamble to the proposed regulations, the "Preferred Standards Path Report for Fluorides" (November 1972) concluded that the most appropriate control strategy is through section 111. A copy of this report is available for inspection during normal business hours at the Freedom of Information Center, Environmental Protection Agency, 401 M Street, SW., Washington, D.C.

Another objection was voiced concerning the preamble statement that the "phosphate fertilizer industry is a major source of fluoride air pollution." According to the "Engineering and Cost Effectiveness Study of Fluoride Emissions

Control" (Contract EHSD 71-14) published in January 1972, the phosphate fertilizer industry ranks near the top of the list of fluoride emitters in the U.S., accounting for nearly 14 percent of the total soluble fluorides emitted every year. The Agency contends that these facts justify naming the phosphate fertilizer industry a major source of fluorides.

DIAMMONIUM PHOSPHATE STANDARD

One commentator contended that the fluoride standard for diammonium phosphate plants could not be met under certain extreme conditions. During periods of high air flow rates through the scrubbing system, high ambient temperatures, and high fluoride content in scrubber liquor, the commentator suggested that the standard would not be met even by sources utilizing best demonstrated control technology. This comment was refuted for two reasons: (1) The surmised extreme conditions would not occur and (2) even if the conditions did occur, the performance of the control system would be such as to meet the standard anyway. Thus the fluoride standard for diammonium phosphate plants was not revised.

POND WATER STANDARDS

The question of the standards for pond water was raised in the comments. The commentator felt that it would have been more logical if the Agency had postponed proposal of the phosphate fertilizer regulations until standards of performance for pond water had also been decided upon, instead of EPA saying that such pond water standards might be set in the future. EPA researched pond water standards along with the other fertilizer standards, but due to the complex nature of pond chemistry and a general lack of available information, simultaneous proposal was not feasible. Rather than delay new source fluoride control regulations, possibly for several years, the Agency decided to proceed with standards for five categories of sources within the industry.

ECONOMIC IMPACT

As was indicated by the comments received, clarification of some of the Agency's statements concerning the economic impact of the standards is necessary. First, the statement that "for three of the five standards there will be no increase in power consumption over that which results from State and local standards" is misleading as written in the preamble to the proposed regulations. The statement should have been qualified in that this conclusion was based on projected construction in the industry through 1980, and was not meant to be applicable past that time. Second, some comments suggested that the cost data in the background document were out of date. Of course the time between the gathering of economic data and the proposal of regulations may be as long as a year or two because of necessary intermediate steps in the standard setting process, however, the economic data are developed with future industry growth and financial status in mind, and therefore, the analysis should be viable at the time of standard proposal. Third, an objection was raised to the statement that "the disparity in cost between triple superphosphate and diammonium phosphate will only hasten the trend toward production of diammonium phosphate." The commentator felt that EPA should not place itself in a position of regulating fertilizer production. In response, the Agency does not set standards to regulate production. The standards are set to employ the best system of emission reduction considering cost. The standards will basically require use of a packed scrubber for compliance in each of the five phosphate fertilizer source categories. In this instance, control costs (although considered reasonable for both source categories) are higher for triple superphosphate plants than for diammonium phosphate plants. The reasons for this are that (1) larger gas volumes must be scrubbed in triple superphosphate facilities and (2) triple suprephosphate storage facility emissions must also be scrubbed. However, the greater costs can be partially offset in a plant producing both granular triple superphosphate and diammonium phosphate with the same manufacturing facility and same control device. Such a facility can optimize utilization of the owner's capital by operating his phosphoric acid plant at full capacity and producing a product mix that will maximize profits. The information gathered by the Agency indicates that all new facilities equipped to manufacture diammonium phosphate will also produce granular triple superphosphate to satisfy demand for direct application materials and exports.

CONTROL OF TOTAL FLUORIDES

Most of the commentators objected to EPA's control of "total fluorides" rather than "gaseous and water soluble fluorides." The rationale for deciding to set standards for total fluorides is presented on pages 5 and 6 of volume 1 of the background document. Essentially the rationale is that some "insoluble" fluoride compounds will slowly dissolve if allowed to remain in the water-impinger section of the sample train. Since EPA did not closely control the time between capture and filtration of the fluoride samples, the change was made to insure a more accurate data base. Additional comments on this subject revealed concern that the switch to total fluorides would bring phosphate rock operations under the standards. EPA did not intend such operations to be controlled by these regulations, and did not include them in the definitions of affected facilities; however, standards for these operations are currently under development within the Agency.

MONITORING REQUIREMENTS

Several comments were received with regard to the sections requiring a flow measuring device which has an accuracy of ± 5 percent over its operating range. The commentators felt that this accuracy could not be met and that the capital and operating costs outweighed anticipated utility. First of all, "weighbelts" are common devices in the phosphate fertilizer industry as raw material feeds are routinely measured. EPA felt there would be no economic impact resulting from this requirement because plants would have normally installed weighing devices anyway. Second, contacts with the industry led EPA to believe that the ± 5 percent accuracy requirement would be easily met, and a search of pertinent literature showed that weighing devices with ± 1 percent accuracy are commercially available.

PERFORMANCE TEST PROCEDURES

Finally some comments specifically addressed § 60.245 (now § 60.244) of the proposed granular triple superphosphate storage facility standards. The first two remarks contended that it is impossible to tell when the storage building is filled to at least 10 percent of the building capacity without requiring an expensive engineering survey, and that it was also impossible to tell how much triple superphosphate in the building is fresh and how much is over 10 days old. EPA's experience has been that plants typically make surveys to determine the amount of triple superphosphate stored, and typically keep good records of the movement of triple superphosphate into and out of storage so that it is possible to make a good estimate of the age and amount of product. In light of data gathered during testing, the Agency disagrees with the above contentions and feels the requirements are reasonable. A third comment stated that § 60.244 (proposed § 60.245) was too restrictive, could not be met with partially filled storage facilities, and that the 10 percent requirement was not valid or practical. In response, the requirement of § 60.244(d)(1) is that "at least 10 percent of the building capacity" contain granular triple superphosphate. This means that, for a performance test, an owner or operator could have more than 10 percent of the building filled. In fact it is to his advantage to have more than 10 percent because of the likelihood of decreased emissions (in units of the standard) as calculated by the equation in § 60.244(g). The data obtained by the Agency show that the standard can be met with partially filled buildings. One commentator did not agree with the requirement in § 60.244(e) [proposed § 60.245(e)] to have at least five days maximum production of fresh granular triple superphosphate in the storage building before a performance test. The commentator felt this section was unreasonable because it dictated production schedules for triple superphosphate. However, this section applies only when the requirements of § 60.244(d)(2) [proposed § 60.245(d)(2)] are not met. In addition this requirement is not unreasonable regarding production schedules because performance tests are not required at regular intervals. A performance test is conducted after a facility begins operation; additional performance tests are conducted only when the facility is suspected of violation of the standard of performance.

Effective date. In accordance with section 111 of the Act, these regulations prescribing standards of performance for the selected stationary sources are effective on August 4, 1975, and apply to sources at which construction or modification commenced after October 22, 1974.

RUSSELL E. TRAIN,
Administrator.

JULY 25, 1975.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. The table of sections is amended by adding Subparts T, U, V, W, and X and revising Appendix A to read as follows:

* * * * *

Subpart T—Standards of Performance for the Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants

60 200 Applicability and designation of affected facility.
60 201 Definitions.
60 202 Standard for fluorides.
60.203 Monitoring of operations.
60 204 Test methods and procedures.

Subpart U—Standards of Performance for the Phosphate Fertilizer Industry: Superphosphoric Acid Plants

60 210 Applicability and designation of affected facility.
60.211 Definitions.
60 212 Standard for fluorides.
60 213 Monitoring of operations.
60.214 Test methods and procedures.

Subpart V—Standards of Performance for the Phosphate Fertilizer Industry: Diammonium Phosphate Plants

60 220 Applicability and designation of affected facility.
60 221 Definitions.
60 222 Standard for fluorides.
60 223 Monitoring of operations.
60.224 Test methods and procedures.

Subpart W—Standards of Performance for the Phosphate Fertilizer Industry: Triple Superphosphate Plants

60 230 Applicability and designation of affected facility.
60.231 Definitions.
60 232 Standard for fluorides.
60 233 Monitoring of operations.
60.234 Test methods and procedures.

Subpart X—Standards of Performance for the Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities

60.240 Applicability and designation of affected facility.
60 241 Definitions.
60 242 Standard for fluorides.
60.243 Monitoring of operations.
60.244 Test methods and procedures.

* * * * *

APPENDIX A—REFERENCE METHODS

Method 1—Sample and velocity traverses for stationary sources.
Method 2—Determination of stack gas velocity and volumetric flow rate (Type S pitot tube).
Method 3—Gas analysis for carbon dioxide, excess air, and dry molecular weight.
Method 4—Determination of moisture in stack gases.
Method 5—Determination of particulate emissions from stationary sources.
Method 6—Determination of sulfur dioxide emissions from stationary sources.
Method 7—Determination of nitrogen oxide emissions from stationary sources.
Method 8—Determination of sulfuric acid mist and sulfur dioxide emissions from stationary sources.
Method 9—Visual determination of the opacity of emissions from stationary sources.
Method 10—Determination of carbon monoxide emissions from stationary sources.
Method 11—Determination of hydrogen sulfide emissions from stationary sources.
Method 12—Reserved.
Method 13A—Determination of total fluoride emissions from stationary sources—SPADNS Zirconium Lake Method.
Method 13B—Determination of total fluoride emissions from stationary sources—Specific Ion Electrode Method.

2. Part 60 is amended by adding subparts T, U, V, W, and X as follows:

Subpart T—Standards of Performance for the Phosphate Fertilizer Industry: Wet-Process Phosphoric Acid Plants

§ 60.200 Applicability and designation of affected facility.

The affected facility to which the provisions of this subpart apply is each wet-process phosphoric acid plant. For the purpose of this subpart, the affected facility includes any combination of: reactors, filters, evaporators, and hotwells.

§ 60.201 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Wet-process phosphoric acid plant" means any facility manufacturing phosphoric acid by reacting phosphate rock and acid.

(b) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.204, or equivalent or alternative methods.

(c) "Equivalent P_2O_5 feed" means the quantity of phosphorus, expressed as phosphorous pentoxide, fed to the process.

§ 60.202 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of 10.0 g/metric ton of equivalent P_2O_5 feed (0.020 lb/ton).

§ 60.203 Monitoring of operations.

(a) The owner or operator of any wet-process phosphoric acid plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a monitoring device which can be used to determine the mass flow of phosphorus-bearing feed material to the process. The monitoring device shall have an accuracy of ±5 percent over its operating range.

(b) The owner or operator of any wet-process phosphoric acid plant shall maintain a daily record of equivalent P_2O_5 feed by first determining the total mass rate in metric ton/hr of phosphorus bearing feed using a monitoring device for measuring mass flowrate which meets the requirements of paragraph (a) of this section and then by proceeding according to § 60.204(d)(2).

(c) The owner or operator of any wet-process phosphoric acid subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the process scrubbing system. The monitoring device shall have an accuracy of ±5 percent over its operating range.

§ 60.204 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided in § 60.8 (b), shall be used to determine compliance with the standard prescribed in § 60.202 as follows:

(1) Method 13A or 13B for the concentration of total fluorides and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 13A or 13B, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for the affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined by applicable test methods and procedures.

(d) Equivalent P_2O_5 feed shall be determined as follows:

(1) Determine the total mass rate in metric ton/hr of phosphorus-bearing feed during each run using a flow monitoring device meeting the requirements of § 60.203(a).

(2) Calculate the equivalent P_2O_5 feed by multiplying the percentage P_2O_5 content, as measured by the spectrophotometric molybdovanadophosphate method (AOAC Method 9), times the total mass rate of phosphorus-bearing feed. AOAC Method 9 is published in the Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11–12. Other methods may be approved by the Administrator.

(e) For each run, emissions expressed in g/metric ton of equivalent P_2O_5 feed shall be determined using the following equation:

$$E = \frac{(C_s Q_s)\ 10^{-3}}{M_{P_2O_5}}$$

where:

E = Emissions of total fluorides in g/metric ton of equivalent P_2O_5 feed.

C_s = Concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.

Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.

10^{-3} = Conversion factor for mg to g.

$M_{P_2O_5}$ = Equivalent P_2O_5 feed in metric ton/hr as determined by § 60.204(d).

Subpart U—Standards of Performance for the Phosphate Fertilizer Industry: Superphosphoric Acid Plants

§ 60.210 Applicability and designation of affected facility.

The affected facility to which the provisions of this subpart apply is each superphosphoric acid plant. For the purpose of this subpart, the affected facility includes any combination of: evaporators, hotwells, acid sumps, and cooling tanks.

§ 60.211 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Superphosphoric acid plant" means any facility which concentrates wet-process phosphoric acid to 66 percent or greater P_2O_5 content by weight for eventual consumption as a fertilizer.

(b) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.214, or equivalent or alternative methods.

(c) "Equivalent P_2O_5 feed" means the quantity of phosphorus, expressed as phosphorous pentoxide, fed to the process.

§ 60.212 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of 5.0 g/metric ton of equivalent P_2O_5 feed (0.010 lb/ton).

§ 60.213 Monitoring of operations.

(a) The owner or operator of any superphosphoric acid plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a flow monitoring device which can be used to determine the mass flow of phosphorus-bearing feed material to the process. The flow monitoring device shall have an accuracy of ± 5 percent over its operating range.

(b) The owner or operator of any superphosphoric acid plant shall maintain a daily record of equivalent P_2O_5 feed by first determining the total mass rate in metric ton/hr of phosphorus-bearing feed using a flow monitoring device meeting the requirements of paragraph (a) of this section and then by proceeding according to § 60.214(d)(2).

(c) The owner or operator of any superphosphoric acid plant subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the process scrubbing system. The monitoring device shall have an accuracy of ± 5 percent over its operating range.

§ 60.214 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.212 as follows:

(1) Method 13A or 13B for the concentration of total fluorides and the associated moisture content.

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 13A or 13B, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be at least 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for the affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined by applicable test methods and procedures.

(d) Equivalent P_2O_5 feed shall be determined as follows:

(1) Determine the total mass rate in metric ton/hr of phosphorus-bearing feed during each run using a flow monitoring device meeting the requirements of § 60.213(a).

(2) Calculate the equivalent P_2O_5 feed by multiplying the percentage P_2O_5 content, as measured by the spectrophotometric molybdovanadophosphate method (AOAC Method 9), times the total mass rate of phosphorus-bearing feed. AOAC Method 9 is published in the Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11–12. Other methods may be approved by the Administrator.

(e) For each run, emissions expressed in g/metric ton of equivalent P_2O_5 feed, shall be determined using the following equation:

$$E = \frac{(C_s Q_s)\ 10^{-3}}{M_{P_2O_5}}$$

where:

E = Emissions of total fluorides in g/metric ton of equivalent P_2O_5 feed.

C_s = Concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.

Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.

10^{-3} = Conversion factor for mg to g.

$M_{P_2O_5}$ = Equivalent P_2O_5 feed in metric ton/hr as determined by § 60.214(d).

Subpart V—Standards of Performance for the Phosphate Fertilizer Industry: Diammonium Phosphate Plants

§ 60.220 Applicability and designation of affected facility.

The affected facility to which the provisions of this subpart apply is each granular diammonium phosphate plant. For the purpose of this subpart, the affected facility includes any combination of: reactors, granulators, dryers, coolers, screens and mills.

§ 60.221 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Granular diammonium phosphate plant" means any plant manufacturing granular diammonium phosphate by reacting phosphoric acid with ammonia.

(b) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.224, or equivalent or alternative methods.

(c) "Equivalent P_2O_5 feed" means the quantity of phosphorus, expressed as phosphorous pentoxide, fed to the process.

§ 60.222 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of 30 g/metric ton of equivalent P_2O_5 feed (0.060 lb/ton).

§ 60.223 Monitoring of operations.

(a) The owner or operator of any granular diammonium phosphate plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a flow monitoring device which can be used to determine the mass flow of phosphorus-bearing feed material to the process. The flow monitoring device shall have an accuracy of ±5 percent over its operating range.

(b) The owner or operator of any granular diammonium phosphate plant shall maintain a daily record of equivalent P_2O_5 feed by first determining the total mass rate in metric ton/hr of phosphorus-bearing feed using a flow monitoring device meeting the requirements of paragraph (a) of this section and then by proceeding according to § 60.224(d)(2).

(c) The owner or operator of any granular diammonium phosphate plant subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the scrubbing system. The monitoring device shall have an accuracy of ±5 percent over its operating range.

§ 60.224 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.222 as follows:

(1) Method 13A or 13B for the concentration of total fluorides and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 13A or 13B, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be at least 0.85 dscm (30 dscf) except that shorter sampling

times or smaller volumes when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for the affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined by applicable test methods and procedures.

(d) Equivalent P_2O_5 feed shall be determined as follows:

(1) Determine the total mass rate in metric ton/hr of phosphorus-bearing feed during each run using a flow monitoring device meeting the requirements of § 60.223(a).

(2) Calculate the equivalent P_2O_5 feed by multiplying the percentage P_2O_5 content, as measured by the spectrophotometric molybdovanadophosphate method (AOAC Method 9), times the total mass rate of phosphorus-bearing feed. AOAC Method 9 is published in the Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11–12. Other methods may be approved by the Administrator.

(e) For each run, emissions expressed in g/metric ton of equivalent P_2O_5 feed shall be determined using the following equation:

$$E = \frac{(C_s Q_s)\ 10^{-3}}{M_{P_2O_5}}$$

where:

E = Emissions of total fluorides in g/metric ton of equivalent P_2O_5.
C_s = Concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.
Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.
10^{-3} = Conversion factor for mg to g.
$M_{P_2O_5}$ = Equivalent P_2O_5 feed in metric ton/hr as determined by § 60.224(d).

Subpart W—Standards of Performance for the Phosphate Fertilizer Industry: Triple Superphosphate Plants

§ 60.230 Applicability and designation of affected facility.

The affected facility to which the provisions of this subpart apply is each triple superphosphate plant. For the purpose of this subpart, the affected facility includes any combination of: Mixers, curing belts (dens), reactors, granulators, dryers, cookers, screens, mills and facilities which store run-of-pile triple superphosphate.

§ 60.231 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Triple superphosphate plant" means any facility manufacturing triple superphosphate by reacting phosphate rock with phosphoric acid. A rule-of-pile triple superphosphate plant includes curing and storing.

(b) "Run-of-pile triple superphosphate" means any triple superphosphate that has not been processed in a granulator and is composed of particles at least 25 percent by weight of which (when not caked) will pass through a 16 mesh screen.

(c) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.234, or equivalent or alternative methods.

(d) "Equivalent P_2O_5 feed" means the quantity of phosphorus, expressed as phosphorus pentoxide, fed to the process.

§ 60.232 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of 100 g/metric ton of equivalent P_2O_5 feed (0.20 lb/ton).

§ 60.233 Monitoring of operations.

(a) The owner or operator of any triple superphosphate plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a flow monitoring device which can be used to determine the mass flow of phosphorus-bearing feed material to the process. The flow monitoring device shall have an accuracy of ±5 percent over its operating range.

(b) The owner or operator of any triple superphosphate plant shall maintain a daily record of equivalent P_2O_5 feed by first determining the total mass rate in metric ton/hr of phosphorus-bearing feed using a flow monitoring device meeting the requirements of paragraph (a) of this section and then by proceeding according to § 60.234(d)(2).

(c) The owner or operator of any triple superphosphate plant subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the process scrubbing system. The monitoring device shall have an accuracy of ±5 percent over its operating range.

§ 60.234 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.232 as follows:

(1) Method 13A or 13B for the concentration of total fluorides and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 13A or 13B, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be at least 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for the affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined by applicable test methods and procedures.

(d) Equivalent P_2O_5 feed shall be determined as follows:

(1) Determine the total mass rate in metric ton/hr of phosphorus-bearing feed during each run using a flow monitoring device meeting the requirements of § 60.233(a).

(2) Calculate the equivalent P_2O_5 feed by multiplying the percentage P_2O_5 content, as measured by the spectrophotometric molybdovanadophosphate method (AOAC Method 9), times the total mass rate of phosphorus-bearing feed. AOAC Method 9 is published in the Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11–12. Other methods may be approved by the Administrator.

(e) For each run, emissions expressed in g/metric ton of equivalent P_2O_5 feed shall be determined using the following equation:

$$E = \frac{(C_s Q_s)\ 10^{-3}}{M_{P_2O_5}}$$

where:

E = Emissions of total fluorides in g/metric ton of equivalent P_2O_5 feed.
C_s = Concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.
Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.
10^{-3} = Conversion factor for mg to g.
$M_{P_2O_5}$ = Equivalent P_2O_5 feed in metric ton/hr as determined by § 60.234(d).

Subpart X—Standards of Performance for the Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities

§ 60.240 Applicability and designation of affected facility.

The affected facility to which the provisions of this subpart apply is each granular triple superphosphate storage facility. For the purpose of this subpart, the affected facility includes any combination of: storage or curing piles, conveyors, elevators, screens and mills.

§ 60.241 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Granular triple superphosphate storage facility" means any facility curing or storing granular triple superphosphate.

(b) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.244, or equivalent or alternative methods.

(c) "Equivalent P_2O_5 stored" means the quantity of phosphorus, expressed as phosphorus pentoxide, being cured or stored in the affected facility.

(d) "Fresh granular triple superphosphate" means granular triple superphosphate produced no more than 10 days prior to the date of the performance test.

§ 60.242 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of 0.25 g/hr/metric ton of equivalent P_2O_5 stored (5.0×10^{-4} lb/hr/ton of equivalent P_2O_5 stored).

§ 60.243 Monitoring of operations.

(a) The owner or operator of any granular triple superphosphate storage facility subject to the provisions of this subpart shall maintain an accurate account of triple superphosphate in storage to permit the determination of the amount of equivalent P_2O_5 stored.

(b) The owner or operator of any granular triple superphosphate storage facility shall maintain a daily record of total equivalent P_2O_5 stored by multiplying the percentage P_2O_5 content, as determined by § 60.244(f)(2), times the total mass of granular triple superphosphate stored.

(c) The owner or operator of any granular triple superphosphate storage facility subject to the provisions of this part shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the process scrubbing sytem. The monitoring device shall have an accuracy of ±5 percent over its operating range.

§ 60.244 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.242 as follows:

(1) Method 13A or 13B for the concentration of total fluorides and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 13A or 13B, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be at least 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for the affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined by applicable test methods and procedures.

(d) Except as provided under paragraph (e) of this section, all performance tests on granular triple superphosphate storage facilities shall be conducted only when the following quantities of product are being cured or stored in the facility:

(1) Total granular triple superphosphate—at least 10 percent of the building capacity.

(2) Fresh granular triple superphosphate—at least 20 percent of the amount of triple superphosphate in the building.

(e) If the provisions set forth in paragraph (d)(2) of this section exceed production capabilities for fresh granular triple superphosphate, the owner or operator shall have at least five days maximum production of fresh granular triple superphosphate in the building during a performance test.

(f) Equivalent P_2O_5 stored shall be determined as follows:

(1) Determine the total mass stored during each run using an accountability system meeting the requirements of § 60.243(a).

(2) Calculate the equivalent P_2O_5 stored by multiplying the percentage P_2O_5 content, as measured by the spectrophotometric molybdovanadophosphate method (AOAC Method 9), times the total mass stored. AOAC Method 9 is published in the Afficial Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11–12. Other methods may be approved by the Administrator.

(g) For each run, emissions expressed in g/hr/metric ton of equivalent P_2O_5 stored shall be determined using the following equation:

$$E = \frac{(C_s Q_s)\ 10^{-3}}{M_{P_2O_5}}$$

where:

E = Emissions of total fluorides in g/hr/metric ton of equivalent P_2O_5 stored.

C_s = Concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.

Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.

10^{-3} = Conversion factor for mg to g.

$M_{P_2O_5}$ = Equivalent P_2O_5 feed in metric tons as measured by § 60.244(d).

3. Part 60 is amended by adding Reference Methods 13A and 13B to Appendix A as follows:

METHOD 13—DETETMINATION OF TOTAL FLUORIDE EMISSIONS FROM STATIONARY SOURCES—SPADNS ZIRCONIUM LAKE METHOD

1. *Principle and Applicability.*

1.1 *Principle.* Gaseous and particulate fluorides are withdrawn isokinetically from the source using a sampling train. The fluorides are collected in the impinger water and on the filter of the sampling train. The weight of total fluorides in the train is determined by the SPADNS Zirconium Lake colorimetric method.

1.2 *Applicability.* This method is applicable for the determination of fluoride emissions from stationary sources only when specified by the test procedures for determining compliance with new source performance standards. Fluorocarbons, such as Freons, are not quantitatively collected or measured by this procedure.

2. *Range and Sensitivity.*

The SPADNS Zirconium Lake analytical method covers the range from 0–1.4 μg/ml fluoride. Sensitivity has not been determined.

3. *Interferences.*

During the laboratory analysis, aluminum in excess of 300 mg/liter and silicon dioxide in excess of 300 μg/liter will prevent complete recovery of fluoride. Chloride will distill over and interfere with the SPADNS Zirconium Lake color reaction. If chloride ion is present, use of Specific Ion Electrode (Method 13B) is recommended; otherwise a chloride determination is required and 5 mg of silver sulfate (see section 7.3.6) must be added for each mg of chloride to prevent chloride interference. If sulfuric acid is carried over in the distillation, it will cause a positive interference. To avoid sulfuric acid carryover, it is important to stop distillation at 175°C.

4. *Precision, Accuracy and Stability.*

4.1 *Analysis.* A relative standard deviation of 3 percent was obtained from twenty replicate intralaboratory determinations on stack emission samples with a concentration range of 39 to 360 mg/l. A phosphate rock standard which was analyzed by this procedure contained a certified value of 3.84 percent. The average of five determinations was 3.88 percent fluoride.

4.2 *Stability.* The color obtained when the sample and colorimetric reagent are mixed is stable for approximately two hours. After formation of the color, the absorbances of the sample and standard solutions should be measured at the same temperature. A 3°C temperature difference between sample and standard solutinos will produce an error of approximately 0 005 mg F/liter.

5. *Apparatus.*

5 1 *Sample train.* See Figure 13A–1; it is similar to the Method 5 train except for the interchangeability of the position of the filter. Commercial models of this train are available. However, if one desires to build his own, complete construction details are described in APTD–0581; for changes from the APTD–0581 document and for allowable modifications to Figure 13A–1, see the following subsections.

The operating and maintenance procedures for the sampling train are described in APTD–0576. Since correct usage is important in obtaining valid results, all users should read the APTD–0576 document and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein.

5.1.1 Probe nozzle—Stainless steel (316) with sharp, tapered leading edge. The angle of taper shall be ≤30° and the taper shall be on the outside to preserve a constant internal diameter. The probe nozzle shall be of the button-hook or elbow design, unless otherwise specified by the Administrator. The wall thickness of the nozzle shall be less than or equal to that of 20 gauge tubing, i.e., 0 165 cm (0.065 in.) and the distance from the tip of the nozzle to the first bend or point of disturbance shall be at least two times the outside nozzle diameter. The nozzle shall be constructed from seamless stainless steel tubing. Other configurations and construction material may be used with approval from the Administrator.

A range of sizes suitable for isokinetic sampling should be available, e.g., 0.32 cm (⅛ in.) up to 1.27 cm (½ in.) (or larger if higher volume sampling trains are used) inside diameter (ID) nozzles in increments of 0.16 cm (1/16 in.). Each nozzle shall be calibrated according to the procedures outlined in the calibration section.

5.1.2 Probe liner—Borosilicate glass or stainless steel (316). When the filter is located immediately after the probe, a probe heating system may be used to prevent filter plugging resulting from moisture condensation. The temperature in the probe shall not exceed 120 ± 14°C (248 ± 25°F).

5.1 3 Pitot tube—Type S, or other device approved by the Administrator, attached to probe to allow constant monitoring of the stack gas velocity. The face openings of the pitot tube and the probe nozzle shall be adjacent and parallel to each other, not necessarily on the same plane, during sampling. The free space between the nozzle and

pitot tube shall be at least 1.9 cm (0.75 in.). The free space shall be set based on a 1.3 cm (0 5 in.) ID nozzle, which is the largest size nozzle used.

The pitot tube must also meet the criteria specified in Method 2 and be calibrated according to the procedure in the calibration section of that method.

5.1.4 Differential pressure gauge—Inclined manometer capable of measuring velocity head to within 10% of the minimum measured value. Below a differential pressure of 1.3 mm (0.05 in.) water gauge, micromanometers with sensitivities of 0.013 mm (0.0005 in.) should be used. However, micromanometers are not easily adaptable to field conditions and are not easy to use with pulsating flow. Thus, other methods or devices acceptable to the Administrator may be used when conditions warrant.

5.1.5 Filter holder—Borosilicate glass with a glass frit filter support and a silicone rubber gasket. Other materials of construction may be used with approval from the Administrator, e.g., if probe liner is stainless steel, then filter holder may be stainless steel. The holder design shall provide a positive seal against leakage from the outside or around the filter.

5.1.6 Filter heating system—When moisture condensation is a problem, any heating system capable of maintaining a temperature around the filter holder during sampling of no greater than $120 \pm 14°C$ ($248 \pm 25°F$). A temperature gauge capable of measuring temperature to within 3°C (5.4°F) shall be installed so that when the filter heater is used, the temperature around the filter holder can be regulated and monitored during sampling. Heating systems other than the one shown in APTD–0581 may be used.

5.1.7 Impingers—Four impingers connected as shown in Figure 13A–1 with ground glass (or equivalent), vacuum tight fittings. The first, third, and fourth impingers are of the Greenburg-Smith design, modified by replacing the tip with a 1¼ cm (½ in.) inside diameter glass tube extending to 1¼ cm (½ in.) from the bottom of the flask. The second impinger is of the Greensburg-Smith design with the standard tip.

5.1.8 Metering system—Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3°C (~5°F), dry gas meter with 2% accuracy at the required sampling rate, and related equipment, or equivalent, as required to maintain an isokinetic sampling rate and to determine sample volume. When the metering system is used in conjunction with a pitot tube, the system shall enable checks of isokinetic rates.

5.1.9 Barometer—Mercury, aneroid, or other barometers capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby weather bureau station, in which case the station value shall be requested and an adjustment for elevation differences shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase.

5.2 *Sample recovery.*

5.2 1 Probe liner and probe nozzle brushes—Nylon bristles with stainless steel wire handles. The probe brush shall have extensions, at least as long as the probe, of stainless steel, teflon, or similarly inert material. Both brushes shall be properly sized and shaped to brush out the probe liner and nozzle.

5.2.2 Glass wash bottles—Two.

5.2.3 Sample storage containers—Wide mouth, high density polyethylene bottles, 1 liter.

5.2.4 Plastic storage containers—Air tight containers of sufficient volume to store silica gel.

5.2.5 Graduated cylinder—250 ml.

5.2.6 Funnel and rubber policeman—to aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.

5.3 *Analysis.*

5.3.1 Distillation apparatus—Glass distillation apparatus assembled as shown in Figure 13A–2.

5.3.2 Hot plate—Capable of heating to 500° C.

5.3.3 Electric muffle furnace—Capable of heating to 600° C.

5.3.4 Crucibles—Nickel, 75 to 100 ml capacity.

5 3.5 Beaker, 1500 ml.

5.3.6 Volumetric flask—50 ml.

5.3.7 Erlenmeyer flask or plastic bottle—500 ml.

5.3.8 Constant temperature bath—Capable of maintaining a constant temperature of ±1.0° C in the range of room temperature.

5.3 9 Balance—300 g capacity to measure to ±0.5 g.

5.3.10 Spectrophotometer — Instrument capable of measuring absorbance at 570 nm and providing at least a 1 cm light path.

5.3.11 Spectrophotometer cells—1 cm.

6. *Reagents*

6.1 *Sampling.*

6.1.1 Filters—Whatman No. 1 filters, or equivalent, sized to fit filter holder.

6.1.2 Silica gel—Indicating type, 6–16 mesh. If previously used, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received.

6.1.3 Water—Distilled.

6.1.4 Crushed ice.

6.1.5 Stopcock grease—Acetone insoluble, heat stable silicone grease. This is not necessary if screw-on connectors with teflon sleeves, or similar, are used.

6.2 *Sample recovery.*

6.2.1 Water—Distilled from same container as 6.1.3.

6.3 *Analysis.*

6.3.1 Calcium oxide (CaO)—Certified grade containing 0.005 percent fluoride or less.

6.3.2 Phenolphthalein Indicator—0.1 percent in 1:1 ethanol-water mixture.

6.3.3 Silver sulfate (Ag_2SO_4)—ACS reagent grade, or equivalent.

6.3.4 Sodium hydroxide (NaOH)—Pellets, ACS reagent grade, or equivalent.

6 3.5 Sulfuric acid (H_2SO_4)—Concentrated, ACS reagent grade, or equivalent.

6.3.6 Filters—Whatman No. 541, or equivalent.

6.3.7 Hydrochloric acid (HCl)—Concentrated, ACS reagent grade, or equivalent.

6.3 8 Water—Distilled, from same container as 6.1.3.

6.3.9 Sodium fluoride—Standard solution. Dissolve 0.2210 g of sodium fluoride in 1 liter of distilled water. Dilute 100 ml of this solution to 1 liter with distilled water. One milliliter of the solution contains 0.01 mg of fluoride.

6.3 10 SPADNS solution—[4,5dihydroxy-3-(p-sulfophenylazo)-2,7-naphthalene - disulfonic acid trisodium salt]. Dissolve 0.960 ±010 g of SPADNS reagent in 500 ml distilled water. This solution is stable for at least one month, if stored in a well-sealed bottle protected from sunlight.

6 3.11 Reference solution—Add 10 ml of SPADNS solution (6 3.10) to 100 ml distilled water and acidify with a solution prepared by diluting 7 ml of concentrated HCl to 10 ml with distilled water. This solution is used to set the spectrophotometer zero point and should be prepared daily.

6 3.12 SPADNS Mixed Reagent—Dissolve 0.135 ±0.005 g of zirconyl chloride octahydrate ($ZrOCl_2.8H_2O$), in 25 ml distilled water. Add 350 ml of concentrated HCl and dilute to 500 ml with distilled water. Mix equal volumes of this solution and SPADNS solution to form a single reagent. This reagent is stable for at least two months.

7. *Procedure.*

NOTE: The fusion and distillation steps of this procedure will not be required, if it can be shown to the satisfaction of the Administrator that the samples contain only water-soluble fluorides.

7.1 *Sampling.* The sampling shall be conducted by competent personnel experienced with this test procedure.

7.1.1 Pretest preparation. All train components shall be maintained and calibrated according to the procedure described in APTD–0576, unless otherwise specified herein.

Weigh approximately 200–300 g of silica gel in air tight containers to the nearest 0.5 g. Record the total weight, both silica gel and container, on the container. More silica gel may be used but care should be taken during sampling that it is not entrained and carried out from the impinger. As an alternative, the silica gel may be weighed directly in the impinger or its sampling holder just prior to the train assembly.

7.1.2 Preliminary determinations. Select the sampling site and the minimum number of sampling points according to Method 1 or as specified by the Administrator. Determine the stack pressure, temperature, and the range of velocity heads using Method 2 and moisture content using Approximation Method 4 or its alternatives for the purpose of making isokinetic sampling rate calculations. Estimates may be used. However, final results will be based on actual measurements made during the test.

Select a nozzle size based on the range of velocity heads such that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates. During the run, do not change the nozzle size. Ensure that the differential pressure gauge is capable of measuring the minimum velocity head value to within 10%, or as specified by the Administrator.

Select a suitable probe liner and probe length such that all traverse points can be sampled. Consider sampling from opposite sides for large stacks to reduce the length of probes.

Select a total sampling time greater than or equal to the minimum total sampling time specified in the test procedures for the specific industry such that the sampling time per point is not less than 2 min. or select some greater time interval as specified by the Administrator, and such that the sample volume that will be taken will exceed the required minimum total gas sample volume specified in the test procedures for the specific industry. The latter is based on an approximate average sampling rate. Note also that the minimum total sample volume is corrected to standard conditions.

It is recommended that a half-integral or integral number of minutes be sampled at each point in order to avoid timekeeping errors.

In some circumstances, e.g. batch cycles, it may be necessary to sample for shorter times at the traverse points and to obtain smaller gas sample volumes. In these cases, the Administrator's approval must first be obtained.

7 1.3 Preparation of collection train. During preparation and assembly of the sampling train, keep all openings where contamination can occur covered until just prior to assembly or until sampling is about to begin.

Place 100 ml of water in each of the first two impingers, leave the third impinger empty, and place approximately 200–300 g or more, if necessary, of preweighed silica gel in the fourth impinger. Record the weight of the silica gel and container on the data sheet. Place the empty container in a clean place for later use in the sample recovery.

Place a filter in the filter holder. Be sure that the filter is properly centered and the

gasket properly placed so as to not allow the sample gas stream to circumvent the filter. Check filter for tears after assembly is completed.

When glass liners are used, install selected nozzle using a Viton A O-ring; the Viton A O-ring is installed as a seal where the nozzle is connected to a glass liner. See APTD-0576 for details. When metal liners are used, install the nozzle as above or by a leak free direct mechanical connection. Mark the probe with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point.

Unless otherwise specified by the Administrator, attach a temperature probe to the metal sheath of the sampling probe so that the sensor extends beyond the probe tip and does not touch any metal. Its position should be about 1.9 to 2.54 cm (0.75 to 1 in.) from the pitot tube and probe nozzle to avoid interference with the gas flow.

Assemble the train as shown in Figure 13A-1 with the filter between the third and fourth impingers. Alternatively, the filter may be placed between the probe and the first impinger. A filter heating system may be used to prevent moisture condensation, but the temperature around the filter holder shall not exceed 120±14°C (248±25°F). [(Note: Whatman No. 1 filter decomposes at 150°C (300°F)).] Record filter location on the data sheet.

Place crushed ice around the impingers.

7.14 Leak check procedure—After the sampling train has been assembled, turn on and set (if applicable) the probe and filter heating system(s) to reach a temperature sufficient to avoid condensation in the probe. Allow time for the temperature to stabilize. Leak check the train at the sampling site by plugging the nozzle and pulling a 380 mm Hg (15 in. Hg) vacuum. A leakage rate in excess of 4% of the average sampling rate or 0.00057 m³/min. (0.02 cfm), whichever is less, is unacceptable.

The following leak check instructions for the sampling train described in APTD-0576 and APTD-0581 may be helpful. Start the pump with by-pass valve fully open and coarse adjust valve completely closed. Partially open the coarse adjust valve and slowly close the by-pass valve until 380 mm Hg (15 in. Hg) vacuum is reached. *Do not* reverse direction of by-pass valve. This will cause water to back up into the filter holder. If 380 mm Hg (15 in. Hg) is exceeded, either leak check at this higher vacuum or end the leak check as described below and start over.

When the leak check is completed, first slowly remove the plug from the inlet to the probe or filter holder and immediately turn off the vacuum pump. This prevents the water in the impingers from being forced backward into the filter holder (if placed before the impingers) and silica gel from being entrained backward into the third impinger.

Leak checks shall be conducted as described whenever the train is disengaged, e.g. for silica gel or filter changes during the test, prior to each test run, and at the completion of each test run. If leaks are found to be in excess of the acceptable rate, the test will be considered invalid. To reduce lost time due to leakage occurrences, it is recommended that leak checks be conducted between port changes.

7.15 Particulate train operation—During the sampling run, an isokinetic sampling rate within 10%, or as specified by the Administrator, of true isokinetic shall be maintained.

For each run, record the data required on the example data sheet shown in Figure 13A-3. Be sure to record the initial dry gas meter reading. Record the dry gas meter readings at the beginning and end of each sampling time increment, when changes in flow rates are made, and when sampling is halted. Take other data point readings at least once at each sample point during each time increment and additional readings when significant changes (20% variation in velocity head readings) necessitate additional adjustments in flow rate. Be sure to level and zero the manometer.

Clean the portholes prior to the test run to minimize chance of sampling deposited material. To begin sampling, remove the nozzle cap, verify (if applicable) that the probe heater is working and filter heater is up to temperature, and that the pitot tube and probe are properly positioned. Position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. Nomographs are available for sampling trains using type S pitot tubes with 0.85±0.02 coefficients (C_p), and when sampling in air or a stack gas with equivalent density (molecular weight, M_d, equal to 29±4), which aid in the rapid adjustment of the isokinetic sampling rate without excessive computations. APTD-0576 details the procedure for using these nomographs. If C_p and M_d are outside the above stated ranges, do not use the nomograph unless appropriate steps are taken to compensate for the deviations.

When the stack is under significant negative pressure (height of impinger stem), take care to close the coarse adjust valve before inserting the probe into the stack to avoid water backing into the filter holder. If necessary, the pump may be turned on with the coarse adjust valve closed.

When the probe is in position, block off the openings around the probe and porthole to prevent unrepresentative dilution of the gas stream.

Traverse the stack cross section, as required by Method 1 or as specified by the Administrator, being careful not to bump the probe nozzle into the stack walls when sampling near the walls or when removing or inserting the probe through the portholes to minimize chance of extracting deposited material.

During the test run, make periodic adjustments to keep the probe and (if applicable) filter temperatures at their proper values. Add more ice and, if necessary, salt to the ice bath, to maintain a temperature of less than 20°C (68°F) at the impinger/silica gel outlet, to avoid excessive moisture losses. Also, periodically check the level and zero of the manometer.

If the pressure drop across the filter becomes high enough to make isokinetic sampling difficult to maintain, the filter may be replaced in the midst of a sample run. It is recommended that another complete filter assembly be used rather than attempting to change the filter itself. After the new filter or filter assembly is installed conduct a leak check. The final emission results shall be based on the summation of all filter catches.

A single train shall be used for the entire sample run, except for filter and silica gel changes. However, if approved by the Administrator, two or more trains may be used for a single test run when there are two or more ducts or sampling ports. The final emission results shall be based on the total of all sampling train catches.

At the end of the sample run, turn off the pump, remove the probe and nozzle from the stack, and record the final dry gas meter reading. Perform a leak check.[1] Calculate percent isokinetic (see calculation section) to determine whether another test run should be made. If there is difficulty in maintaining isokinetic rates due to source conditions, consult with the Administrator for possible variance on the isokinetic rates.

7.2 Sample recovery. Proper cleanup procedure begins as soon as the probe is removed from the stack at the end of the sampling period.

When the probe can be safely handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it to keep from losing part of the sample. Do not cap off the probe tip tightly while the sampling train is cooling down, as this would create a vacuum in the filter holder, thus drawing water from the impingers into the filter.

Before moving the sample train to the cleanup site, remove the probe from the sample train, wipe off the silicone grease, and cap the open outlet of the probe. Be careful not to lose any condensate, if present. Wipe off the silicone grease from the filter inlet where the probe was fastened and cap it. Remove the umbilical cord from the last impinger and cap the impinger. After wiping off the silicone grease, cap off the filter holder outlet and impinger inlet. Ground glass stoppers, plastic caps, or serum caps may be used to close these openings.

Transfer the probe and filter-impinger assembly to the cleanup area. This area should be clean and protected from the wind so that the chances of contaminating or losing the sample will be minimized.

Inspect the train prior to and during disassembly and note any abnormal conditions. Using a graduated cylinder, measure and record the volume of the water in the first three impingers, to the nearest ml; any condensate in the probe should be included in this determination. Treat the samples as follows:

7.2.1 Container No. 1. Transfer the impinger water from the graduated cylinder to this container. Add the filter to this container. Wash all sample exposed surfaces, including the probe tip, probe, first three impingers, impinger connectors, filter holder, and graduated cylinder thoroughly with distilled water. Wash each component three separate times with water and clean the probe and nozzle with brushes. A maximum wash of 500 ml is used, and the washings are added to the sample container which must be made of polyethylene.

7.2.2 Container No. 2. Transfer the silica gel from the fourth impinger to this container and seal.

7.3 *Analysis.* Treat the contents of each sample container as described below.

7.3.1 Container No. 1.

7.3.1.1 Filter this container's contents, including the Whatman No. 1 filter, through Whatman No. 541 filter paper, or equivalent into a 1500 ml beaker. Note: If filtrate volume exceeds 900 ml make filtrate basic with NaOH to phenolphthalein and evaporate to less than 900 ml.

7.3.1.2 Place the Whatman No. 541 filter containing the insoluble matter (including the Whatman No. 1 filter) in a nickel crucible, add a few ml of water and macerate the filter with a glass rod.

Add 100 mg CaO to the crucible and mix the contents thoroughly to form a slurry. Add a couple of drops of phenolphthalein indicator. The indicator will turn red in a basic medium. The slurry should remain basic during the evaporation of the water or fluoride ion will be lost. If the indicator turns colorless during the evaporation, an acidic condition is indicated. If this happens add CaO until the color turns red again.

Place the crucible in a hood under infrared lamps or on a hot plate at low heat. Evaporate the water completely.

After evaporation of the water, place the crucible on a hot plate under a hood and slowly increase the temperature until the paper chars. It may take several hours for complete charring of the filter to occur.

[1] With acceptability of the test run to be based on the same criterion as in 7.1.4.

Place the crucible in a cold muffle furnace and gradually (to prevent smoking) increase the temperature to 600°C. and maintain until the contents are reduced to an ash. Remove the crucible from the furnace and allow it to cool.

7 3.1 3 Add approximately 4 g of crushed NaOH to the crucible and mix. Return the crucible to the muffle furnace, and fuse the sample for 10 minutes at 600°C.

Remove the sample from the furnace and cool to ambient temperature. Using several rinsings of warm distilled water transfer the contents of the crucible to the beaker containing the filtrate from container No. 1 (7 3.1). To assure complete sample removal, rinse finally with two 20 ml portions of 25 percent (v/v) sulfuric acid and carefully add to the beaker. Mix well and transfer a one-liter volumetric flask. Dilute to volume with distilled water and mix thoroughly. Allow any undissolved solids to settle.

7.3 2 Container No. 2. Weigh the spent silica gel and report to the nearest 0.5 g.

7 3 3 Adjustment of acid/water ratio in distillation flask—(Utilize a protective shield when carrying out this procedure.) Place 400 ml of distilled water in the distilling flask and add 200 ml of concentrated H_2SO_4. Caution: Observe standard precautions when mixing the H_2SO_4 by slowly adding the acid to the flask with constant swirling. Add some soft glass beads and several small pieces of broken glass tubing and assemble the apparatus as shown in Figure 13A-2 Heat the flask until it reaches a temperature of 175°C to adjust the acid/water ratio for subsequent distillations. Discard the distillate.

7.3 4 Distillation—Cool the contents of the distillation flask to below 80° C. Pipette an aliquot of sample containing less than 0 6 mg F directly into the distilling flask and add distilled water to make a total volume of 220 ml added to the distilling flask. [For an estimate of what size aliquot does not exceed 0 6 mg F, select an aliquot of the solution and treat as described in Section 7 3 6. This will give an approximation of the fluoride content, but only an approximation since interfering ions have not been removed by the distillation step.]

Place a 250 ml volumetric flask at the condenser exit. Now begin distillation and gradually increase the heat and collect all the distillation up to 175°C. Caution: Heating the solution above 175°C will cause sulfuric acid to distill over.

The acid in the distilling flask can be used until there is carryover of interferences or poor fluoride recovery An occasional check of fluoride recovery with standard solutions is advised. The acid should be changed whenever there is less than 90 percent recovery or blank values are higher than 0.1 μg/ml. Note: If the sample contains chloride, add 5 mg Ag_2SO_4 to the flask for every mg of chloride. Gradually increase the heat and collect at the distillate up to 175°C. Do not exceed 175°C.

7 3 5 Determination of Concentration—Bring the distillate in the 250 ml volumetric flask to the mark with distilled water and mix thoroughly. Pipette a suitable aliquot from the distillate (containing 10 μg to 40 μg fluoride) and dilute to 50 ml with distilled water. Add 10 ml of SPADNS Mixed Reagent (see Section 6 3 12) and mix thoroughly.

After mixing, place the sample in a constant temperature bath containing the standard solution for thirty minutes before reading the absorbance with the spectrophotometer.

Set the spectrophotometer to zero absorbance at 570 nm with reference solution (6.3.11), and check the spectrophotometer calibration with the standard solution. Determine the absorbance of the samples and determine the concentration from the calibration curve. If the concentration does not fall within the range of the calibration curve, repeat the procedure using a different size aliquot.

8. *Calibration.*

Maintain a laboratory log of all calibrations.

8.1 Sampling Train.

8 1.1 Probe nozzle—Using a micrometer, measure the inside diameter of the nozzle to the nearest 0.025 mm (0.001 in). Make 3 separate measurements using different diameters each time and obtain the average of the measurements. The difference between the high and low numbers shall not exceed 0.1 mm (0.004 in.).

When nozzles become nicked, dented, or corroded, they shall be reshaped, sharpened, and recalibrated before use.

Each nozzle shall be permanently and uniquely identified.

8.1 2 Pitot tube—The pitot tube shall be calibrated according to the procedure outlined in Method 2.

8 1.3 Dry gas meter and orifice meter. Both meters shall be calibrated according to the procedure outlined in APTD-0576. When diaphragm pumps with by-pass valves are used, check for proper metering system design by calibrating the dry gas meter at an additional flow rate of 0.0057 m³/min (0 2 cfm) with the by-pass valve fully opened and then with it fully closed If there is more than ±2 percent difference in flow rates when compared to the fully closed position of the by-pass valve, the system is not designed properly and must be corrected

8 1.4 Probe heater calibration—The probe heating system shall be calibrated according to the procedure contained in APTD-0576. Probes constructed according to APTD-0581 need not be calibrated if the calibration curves in APTD-0576 are used.

8.1 5 Temperature gauges—Calibrate dial and liquid filled bulb thermometers against mercury-in-glass thermometers. Thermocouples need not be calibrated For other devices, check with the Administrator.

8 2 Analytical Apparatus Spectrophotometer Prepare the blank standard by adding 10 ml of SPADNS mixed reagent to 50 my of distilled water. Accurately prepare a series of standards from the standard fluoride solution (see Section 6 3.9) by diluting 2, 4, 6, 8, 10, 12, and 14 ml volumes to 100 ml with distilled water. Pipette 50 ml from each solution and transfer to a 100 ml beaker. Then add 10 ml of SPADNS mixed reagent to each. These standards will contain 0, 10, 20, 30, 40, 50, 60, and 70 μg of fluoride (0—1.4 μg/ml) respectively.

After mixing, place the reference standards and reference solution in a constant temperature bath for thirty minutes before reading the absorbance with the spectrophotometer. All samples should be adjusted to this same temperature before analyzing. Since a 3°C temperature difference between samples and standards will produce an error of approximately 0 005 mg F/liter, care must be taken to see that samples and standards are at nearly identical temperatures when absorbances are recorded

With the spectrophotometer at 570 nm, use the reference solution (see section 6 3 11) to set the absorbance to zero

Determine the absorbance of the standards Prepare a calibration curve by plotting μg F/50 ml versus absorbance on linear graph paper. A standard curve should be prepared initially and thereafter whenever the SPADNS mixed reagent is newly made Also, a calibration standard should be run with each set of samples and if it differs from the calibration curve by ±2 percent, a new standard curve should be prepared.

9. *Calculations.*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

9.1 *Nomenclature.*

A_d = Aliquot of distillate taken for color development, ml.

A_n = Cross sectional area of nozzle, m^2 (ft^2).

A_t = Aliquot of total sample added to still, ml.

B_{ws} = Water vapor in the gas stream, proportion by volume.

C_s = Concentration of fluoride in stack gas, mg/m^3, corrected to standard conditions of 20° C, 760 mm Hg (68° F, 29.92 in. Hg) on dry basis.

F_t = Total weight of fluoride in sample, mg.

μgF = Concentration from the calibration curve, μg.

I = Percent of isokinetic sampling.

m_n = Total amount of particulate matter collected, mg.

M_w = Molecular weight of water, 18 g/g-mole (18 lb/lb-mole).

m_a = Mass of residue of acetone after evaporation, mg.

P_{bar} = Barometric pressure at the sampling site, mm Hg (in. Hg).

P_s = Absolute stack gas pressure, mm Hg (in. Hg).

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R = Ideal gas constant, 0 06236 mm Hg-m^3/°K-g-mole (21 83 in. Hg-ft^3/°R-lb-mole).

T_m = Absolute average dry gas meter temperature (see fig. 13A-3), °K (°R).

T_s = Absolute average stack gas temperature (see fig. 13A-3), °K (°R).

T_{std} = Standard absolute temperature, 293° K (528° R).

V_a = Volume of acetone blank, ml

V_{aw} = Volume of acetone used in wash, ml.

V_d = Volume of distillate collected, ml.

V_{lc} = Total volume of liquid collected in impingers and silica gel, ml. Volume of water in silica gel equals silica gel weight increase in grams times 1 ml/gram. Volume of liquid collected in impinger equals final volume minus initial volume.

V_m = Volume of gas sample as measured by dry gas meter, dcm (dcf).

$V_{m(std)}$ = Volume of gas sample measured by the dry gas meter corrected to standard conditions, dscm (dscf).

$V_{w(std)}$ = Volume of water vapor in the gas sample corrected to standard conditions, scm (scf).

V_t = Total volume of sample, ml.

v_s = Stack gas velocity, calculated by Method 2, Equation 2-7 using data obtained from Method 5, m/sec (ft/sec).

W_a = Weight of residue in acetone wash, mg.

ΔH = Average pressure differential across the orifice (see fig. 13A-3), meter, mm H_2O (in. H_2O).

ρ_a = Density of acetone, mg/ml (see label on bottle).

ρ_w = Density of water, 1 g/ml (0 00220 lb/ml).

θ = Total sampling time, min.

13.6 = Specific gravity of mercury.

60 = Sec/min.

100 = Conversion to percent.

9 2 Average dry gas meter temperature and average orifice pressure drop. See data sheet (fig 13A-3).

9 3 Dry gas volume. Correct the sample volume measured by the dry gas meter to standard conditions [20° C, 760 mm Hg (68° F, 29.92 inches Hg)] by using equation 13A-1.

$$V_{m(std)} = V_m \frac{T_{std}}{T_m}\left[\frac{P_{bar}+\frac{\Delta H}{13.6}}{P_{std}}\right] = KV_m \frac{P_{bar}+\Delta H/13.6}{T_m}$$

equation 13A-1

where:
K=0.3855 °K/mm Hg for metric units.
=17.65 °R/in. Hg for English units.

9.4 Volume of water vapor.

$$V_{w(std)} = V_{lc} \frac{\rho_w}{M_w} \frac{RT_{std}}{P_{std}} = KV_{lc}$$

equation 13A-2

where:
K=0.00134 m³/ml for metric units.
=0.0472 ft³/ml for English units.

9.5 Moisture content.

$$B_{ws} = \frac{V_{w(std)}}{V_{m(std)}+V_{w(std)}}$$

equation 13A-3

If the liquid droplets are present in the gas stream assume the stream to be saturated and use a psychrometric chart to obtain an approximation of the moisture percentage.

9.6 Concentration.

9.6.1 Calculate the amount of fluoride in the sample according to Equation 13A-4.

$$F_t = K \frac{V_t}{A_t} \frac{V_d}{A_d} (\mu g\ F)$$

equation 13A-4

where:
K=10⁻³ mg/μg.

9.6.2 Concentration of fluoride in stack gas. Determine the concentration of fluoride in the stack gas according to Equation 13A-5.

$$C_s = K \frac{F_t}{V_{m(std)}}$$

equation 13A-5

where:
K=35.31 ft³/m³.

9.7 Isokinetic variation.

9.7.1 Calculations from raw data.

$$I = \frac{100\ T_s\ [KV_{lc}+(V_m/T_m)\ (P_{bar}+\Delta H/13.6)]}{60\ \theta\ v_s P_s A_n}$$

equation 13A-6

where:
K=0.00346 mm Hg-m³/ml-°K for metric units.
=0.00267 in. Hg-ft³/ml-°R for English units.

9.7.2 Calculations from intermediate values.

$$I = \frac{T_s V_{m(std)} P_{std}\ 100}{T_{std} v_s \theta A_n P_s\ 60\ (1-B_{ws})} = K \frac{T_s V_{m(std)}}{P_s v_s A_n \theta\ (1-B_{ws})}$$

equation 13A-7

where:
K=4.323 for metric units.
=0.0944 for English units.

9.8 Acceptable results. The following range sets the limit on acceptable isokinetic sampling results:

If 90 percent $<I<$ 110 percent, the results are acceptable. If the results are low in comparison to the standards and I is beyond the acceptable range, the Administrator may option to accept the results. Use reference 7.4 to make judgments. Otherwise, reject the results and repeat the test.

10. *References.*

Bellack, Ervin, "Simplified Fluoride Distillation Method," *Journal of the American Water Works Association* #50: 530-6 (1958).

MacLeod, Kathryn E., and Howard L. Crist, "Comparison of the SPADNS—Zirconium Lake and Specific Ion Electrode Methods of Fluoride Determination in Stack Emission Samples," *Analytical Chemistry* 45: 1272-1273 (1973).

Martin, Robert M., "Construction Details of Isokinetic Source Sampling Equipment," Environmental Protection Agency, Air Pollution Control Office Publication No. APTD-0581.

1973 Annual Book of ASTM Standards, Part 23, Designation: D 1179-72.

Rom, Jerome J., "Maintenance, Calibration, and Operation of Isokinetic Source Sampling Equipment," Environmental Protection Agency, Air Pollution Control Office Publication No. APTD-0576.

Standard Methods for the Examination of Water and Waste Water, published jointly by American Public Health Association, American Water Works Association and Water Pollution Control Federation, 13th Edition (1971).

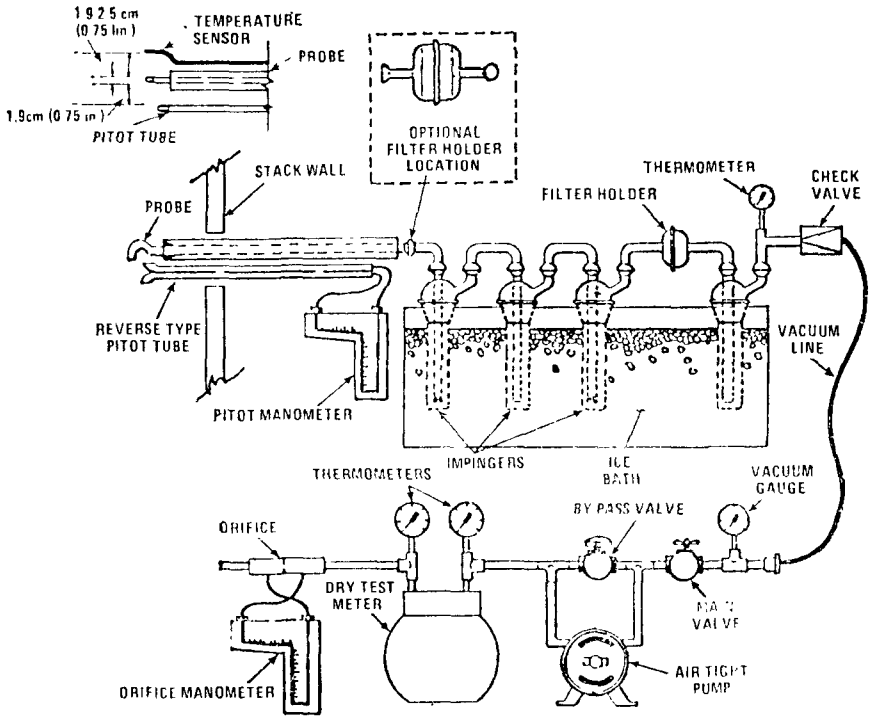


Figure 13A-1. Fluoride sampling train.

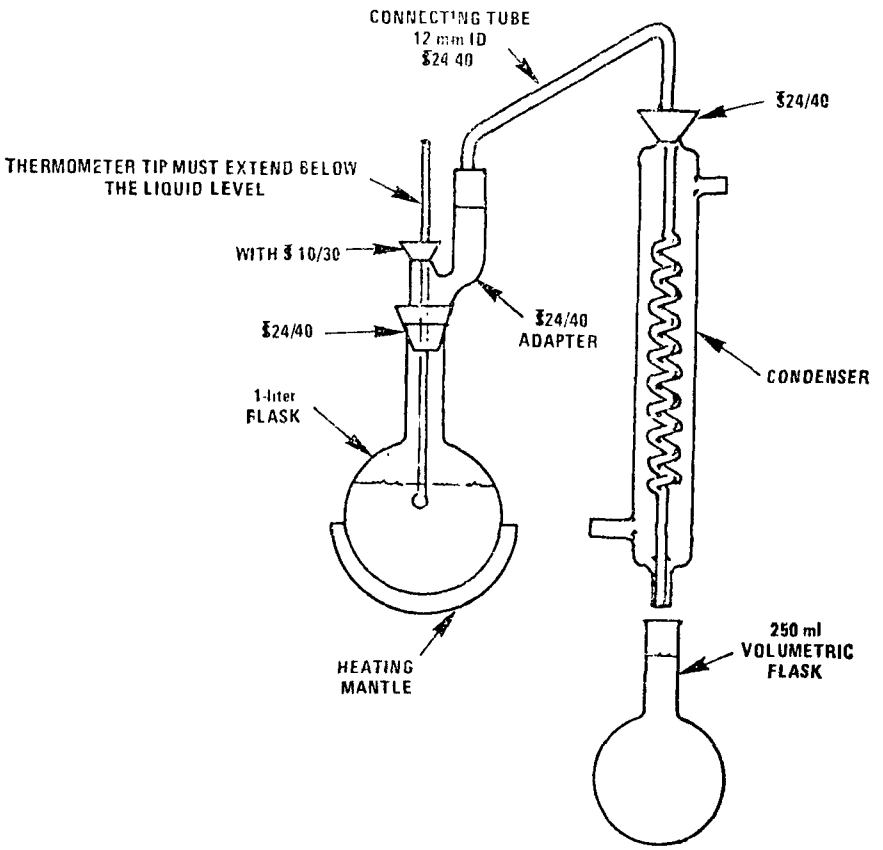


Figure 13A-2. Fluoride Distillation Apparatus

PLANT _____
LOCATION _____
OPERATOR _____
DATE _____
RUN NO _____
SAMPLE BOX NO. _____
METER BOX NO. _____
METER ΔH@ _____
C FACTOR _____
PITOT TUBE COEFFICIENT, C_p _____

SCHEMATIC OF STACK CROSS SECTION

AMBIENT TEMPERATURE _____
BAROMETRIC PRESSURE _____
ASSUMED MOISTURE, % _____
PROBE LENGTH, m (ft) _____
NOZZLE IDENTIFICATION NO. _____
AVERAGE CALIBRATED NOZZLE DIAMETER, cm (in.) _____
PROBE HEATER SETTING _____
LEAK RATE, m^3/min (cfm) _____
PROBE LINER MATERIAL _____

TRAVERSE POINT NUMBER	SAMPLING TIME (θ) min.	STATIC PRESSURE mm Hg (in Hg)	STACK TEMPERATURE (T_s) °C (°F)	VELOCITY HEAD (ΔP_s),	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER mm H_2O (in. H_2O)	GAS SAMPLE VOLUME m^3 (ft^3)	GAS SAMPLE TEMPERATURE AT DRY GAS METER		FILTER HOLDER TEMPERATURE, °C (°F)	TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °C (°F)
							INLET °C (°F)	OUTLET °C (°F)		
TOTAL							Avg	Avg		
AVERAGE							Avg			

Figure 13A-3 Field data

METHOD 13B—DETERMINATION OF TOTAL FLUORIDE EMISSIONS FROM STATIONARY SOURCES—SPECIFIC ION ELECTRODE METHOD.

1 *Principle and Applicability.*

1.1 Principle. Gaseous and particulate fluorides are withdrawn isokinetically from the source using a sampling train. The fluorides are collected in the impinger water and on the filter of the sampling train. The weight of total fluorides in the train is determined by the specific ion electrode method.

1.2 Applicability. This method is applicable for the determination of fluoride emissions from stationary sources only when specified by the test procedures for determining compliance with new source performance standards. Fluorocarbons such as Freons, are not quantitatively collected or measured by this procedure.

2 *Range and Sensitivity.*

The fluoride specific ion electrode analytical method covers the range of 0.02–2,000 μg F/ml; however, measurements of less than 0.1 μg F/ml require extra care. Sensitivity has not been determined.

3. *Interferences.*

During the laboratory analysis, aluminum in excess of 300 mg/liter and silicon dioxide in excess of 300 μg/liter will prevent complete recovery of fluoride.

4 *Precision, Accuracy and Stability.*

The accuracy of fluoride electrode measurements has been reported by various researchers to be in the range of 1–5 percent in a concentration range of 0.04 to 80 mg/l. A change in the temperature of the sample will change the electrode response, a change of 1°C will produce a 1.5 percent relative error in the measurement. Lack of stability in the electrometer used to measure EMF can introduce error. An error of 1 millivolt in the EMF measurement produces a relative error of 4 percent regardless of the absolute concentration being measured.

5 *Apparatus.*

5.1 Sample train. See Figure 13A-1 (Method 13A); it is similar to the Method 5 train except for the interchangeability of the position of the filter. Commercial models of this train are available. However, if one desires to build his own, complete construction details are described in APTD-0581; for changes from the APTD-0581 document and for allowable modifications to Figure 13A-1, see the following subsections.

The operating and maintenance procedures for the sampling train are described in APTD-0576. Since correct usage is important in obtaining valid results, all users should read the APTD-0576 document and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein.

5.1.1 Probe nozzle—Stainless steel (316) with sharp, tapered leading edge. The angle of taper shall be ≤30° and the taper shall be on the outside to preserve a constant internal diameter. The probe nozzle shall be of the button-hook or elbow design, unless otherwise specified by the Administrator. The wall thickness of the nozzle shall be less than or equal to that of 20 gauge tubing, i.e., 0.165 cm (0.065 in.) and the distance from the tip of the nozzle to the first bend or point of disturbance shall be at least two times the outside nozzle diameter. The nozzle shall be constructed from seamless stainless steel tubing. Other configurations and construction material may be used with approval from the Administrator.

A range of sizes suitable for isokinetic sampling should be available, e.g., 0.32 cm (⅛ in.) up to 1.27 cm (½ in.) (or larger if higher volume sampling trains are used) inside diameter (ID) nozzles in increments of 0.16 cm (1/16 in.). Each nozzle shall be calibrated according to the procedures outlined in the calibration section.

5.1.2 Probe liner—Borosilicate glass or stainless steel (316). When the filter is located immediately after the probe, a probe heating system may be used to prevent filter plugging resulting from moisture condensation. The temperature in the probe shall not exceed 120±14°C (248±25 F).

5.1.3 Pitot tube—Type S, or other device approved by the Administrator, attached to probe to allow constant monitoring of the stack gas velocity. The face openings of the pitot tube and the probe nozzle shall be adjacent and parallel to each other, not necessarily on the same plane, during sampling. The free space between the nozzle and pitot tube shall be at least 1.9 cm (0.75 in.). The free space shall be set based on a 1.3 cm (0.5 in.) ID nozzle, which is the largest size nozzle used.

The pitot tube must also meet the criteria specified in Method 2 and be calibrated according to the procedure in the calibration section of that method.

5.1.4 Differential pressure gauge—Inclined manometer capable of measuring velocity head to within 10 percent of the minimum measured value. Below a differential pressure of 1.3 mm (0.05 in.) water gauge, micromanometers with sensitivities of 0.013 mm (0.0005 in.) should be used. However, micromanometers are not easily adaptable to field conditions and are not easy to use with pulsating flow. Thus, other methods or devices acceptable to the Administrator may be used when conditions warrant.

5.1.5 Filter holder—Borosilicate glass with a glass frit filter support and a silicone rubber gasket. Other materials of construction may be used with approval from the Administrator, e.g. if probe liner is stainless steel, then filter holder may be stainless steel. The holder design shall provide a positive seal against leakage from the outside or around the filter.

5.1.6 Filter heating system—When moisture condensation is a problem, any heating system capable of maintaining a temperature around the filter holder during sampling of no greater than 120 ± 14°C (248 ± 25°F). A temperature gauge capable of measuring temperature to within 3°C (5.4°F) shall be installed so that when the filter heater is used, the temperature around the filter holder can be regulated and monitored during sampling. Heating systems other than the one shown in APTD-0581 may be used.

5.1.7 Impingers—Four impingers connected as shown in Figure 13A-1 with ground glass (or equivalent), vacuum tight fittings. The first, third, and fourth impingers are of the Greenburg-Smith design, modified by replacing the tip with a 1¼ cm (½ in.) inside diameter glass tube extending to 1¼ cm (½ in.) from the bottom of the flask. The second impinger is of the Greenburg-Smith design with the standard tip.

5.1.8 Metering system—Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3°C (5.4°F), dry gas meter with 2 percent accuracy at the required sampling rate, and related equipment, or equivalent, as required to maintain an isokinetic sampling rate and to determine sample volume. When the metering system is used in conjunction with a pitot tube, the system shall enable checks of isokinetic rates.

5.1.9 Barometer—Mercury, aneroid, or other barometers capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby weather bureau station, in which case the station value shall be requested and an adjustment for elevation differences shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase.

5.2 Sample recovery.

5.2.1 Probe liner and probe nozzle brushes—Nylon bristles with stainless steel wire handles. The probe brush shall have extensions, at least as long as the probe, of stainless steel, teflon, or similarly inert material. Both brushes shall be properly sized and shaped to brush out the probe liner and nozzle.

5.2.2 Glass wash bottles—Two.

5.2.3 Sample storage containers—Wide mouth, high density polyethylene bottles, 1 liter.

5.2.4 Plastic storage containers—Air tight containers of sufficient volume to store silica gel.

5.2.5 Graduated cylinder—250 ml.

5.2.6 Funnel and rubber policeman—To aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.

5 3 Analysis.

5.3.1 Distillation apparatus—Glass distillation apparatus assembled as shown in Figure 13A-2 (Method 13A).

5.3 2 Hot plate—Capable of heating to 500°C.

5.3.3 Electric muffle furnace—Capable of heating to 600°C.

5.3.4 Crucibles—Nickel, 75 to 100 ml capacity.

5.3 5 Beaker—1500 ml.

5.3.6 Volumetric flask—50 ml.

5.3.7 Erlenmeyer flask or plastic bottle—500 ml.

5.3.8 Constant temperature bath—Capable of maintaining a constant temperature of ±1.0°C in the range of room temperature.

5.3.9 Trip balance—300 g capacity to measure to ±0.5 g.

5.3.10 Fluoride ion activity sensing electrode.

5.3.11 Reference electrode—Single junction; sleeve type. (A combination-type electrode having the references electrode and the fluoride-ion sensing electrode built into one unit may also be used).

5.3.12 Electrometer—A pH meter with millivolt scale capable of ±0.1 mv resolution, or a specific ion meter made specifically for specific ion use.

5.3.13 Magnetic stirrer and TFE fluorocarbon coated stripping bars.

6. *Reagents.*

6.1 Sampling.

6.1.1 Filters—Whatman No. 1 filters, or equivalent, sized to fit filter holder.

6.1.2 Silica get—Indicating type, 6–16 mesh. If previously used, dry at 175°C (350°F) for 2 hours. New silica gel may be used as received.

6.1.3 Water—Distilled.

6.1.4 Crushed ice.

6.1.5 Stopcock grease—Acetone insoluble, heat stable silicone grease. This is not necessary if screw-on connectors with teflon sleeves, or similar, are used.

6.2 Sample recovery.

6.2.1 Water—Distilled from same container as 6.1.3.

6.3 Analysis.

6.3.1 Calcium oxide (CaO)—Certified grade containing 0.005 percent fluoride or less.

6.3.2 Phenolphthalein Indicator—0.1 percent in 1:1 ethanol water mixture.

6.3.3 Sodium hydroxide (NaOH)—Pellets, ACS reagent grade or equivalent.

6.3.4 Sulfuric acid (H_2SO_4)—Concentrated, ACS reagent grade or equivalent.

6 3.' Filters—Whatman No. 541, or equivalent.

6.3.6 Water—Distilled, from same container as 6.1.3.

6.3.7 Total Ionic Strength Adjustment Buffer (TISAB)—Place approximately 500 ml of distilled water in a 1-liter beaker. Add 57 ml glacial acetic acid, 58 g sodium chloride, and 4 g CDTA (Cyclohexylene dinitrilo tetraacetic acid). Stir to dissolve. Place the beaker in a water bath to cool it. Slowly add 5 M NaOH to the solution, measuring the pH continuously with a calibrated pH/reference electrode pair, until the pH is 5.3. Cool to room temperature Pour into a 1-liter flask and dilute to volume with distilled water. Commercially prepared TISAB buffer may be substituted for the above.

6 3 8 Fluoride Standard Solution—0.1 M fluoride reference solution Add 4.20 grams of reagent grade sodium fluoride (NaF) to a 1-liter volumetric flask and add enough distilled water to dissolve. Dilute to volume with distilled water.

7. *Procedure.*

NOTE: The fusion and distillation steps of this procedure will not be required, if it can be shown to the satisfaction of the Administrator that the samples contain only water-soluble fluorides.

7.1 Sampling. The sampling shall be conducted by competent personnel experienced with this test procedure

7.1.1 Pretest preparation. All train components shall be maintained and calibrated according to the procedure described in APTD–0576, unless otherwise specified herein.

Weigh approximately 200–300 g of silica gel in air tight containers to the nearest 0.5 g. Record the total weight, both silica gel and container, on the container. More silica gel may be used but care should be taken during sampling that it is not entrained and carried out from the impinger. As an alternative, the silica gel may be weighed directly in the impinger or its sampling holder just prior to the train assembly.

7.1.2 Preliminary determinations. Select the sampling site and the minimum number of sampling points according to Method 1 or as specified by the Administrator. Determine the stack pressure, temperature, and the range of velocity heads using Method 2 and moisture content using Approximation Method 4 or its alternatives for the purpose of making isokinetic sampling rate calculations. Estimates may be used. However, final results will be based on actual measurements made during the test.

Select a nozzle size based on the range of velocity heads such that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates. During the run, do not change the nozzle size. Ensure that the differential pressure gauge is capable of measuring the minimum velocity head value to within 10 percent, or as specified by the Administrator.

Select a suitable probe liner and probe length such that all traverse points can be sampled. Consider sampling from opposite sides for large stacks to reduce the length of probes.

Select a total sampling time greater than or equal to the minimum total sampling time specified in the test procedures for the specific industry such that the sampling time per point is not less than 2 min. or select some greater time interval as specified by the Administrator, and such that the sample volume that will be taken will exceed the required minimum total gas sample volume specified in the test procedures for the specific industry. The latter is based on an approximate average sampling rate. Note also that the minimum total sample volume is corrected to standard conditions.

It is recommended that a half-integral or integral number of minutes be sampled at each point in order to avoid timekeeping errors.

In some circumstances, e g. batch cycles, it may be necessary to sample for shorter times at the traverse points and to obtain smaller gas sample volumes. In these cases, the Administrator's approval must first be obtained.

7 13 Preparation of collection train During preparation and assembly of the sampling train, keep all openings where contamination can occur covered until just prior to assembly or until sampling is about to begin.

Place 100 ml of water in each of the first two impingers, leave the third impinger empty, and place approximately 200–300 g or more, if necessary, of preweighed silica gel in the fourth impinger Record the weight of the silica gel and container on the data sheet. Place the empty container in a clean place for later use in the sample recovery

Place a filter in the filter holder Be sure that the filter is properly centered and the gasket properly placed so as to not allow the sample gas stream to circumvent the filter. Check filter for tears after assembly is completed.

When glass liners are used, install selected nozzle using a Viton A O-ring; the Viton A O-ring is installed as a seal where the nozzle is connected to a glass liner. See APTD–0576 for details. When metal liners are used, install the nozzle as above or by a leak free direct mechanical connection. Mark the probe with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point.

Unless otherwise specified by the Administrator, attach a temperature probe to the metal sheath of the sampling probe so that the sensor extends beyond the probe tip and does not touch any metal. Its position should be about 1.9 to 2 54 cm (0.75 to 1 in.) from the pitot tube and probe nozzle to avoid interference with the gas flow.

Assemble the train as shown in Figure 13A–1 (Method 13A) with the filter between the third and fourth impingers. Alternatively, the filter may be placed between the probe and first impinger. A filter heating system may be used to prevent moisture condensation, but the temperature around the filter holder shall not exceed 1200±14°C (248±25°F). [(Note: Whatman No. 1 filter decomposes at 150°C (300°F)).] Record filter location on the data sheet.

Place crushed ice around the impingers.

7 1.4 Leak check procedure—After the sampling train has been assembled, turn on and set (if applicable) the probe and filter heating system(s) to reach a temperature sufficient to avoid condensation in the probe. Allow time for the temperature to stabilize. Leak check the train at the sampling site by plugging the nozzle and pulling a 380 mm Hg (15 in. Hg) vacuum. A leakage rate in excess of 4% of the average sampling rate of 0 0057 m³/min. (0.02 cfm), whichever is less, is unacceptable.

The following leak check instruction for the sampling train described in APTD–0576 and APTD–0581 may be helpful. Start the pump with by-pass valve fully open and coarse adjust valve completely closed. Partially open the coarse adjust valve and slowly close the by-pass valve until 380 mm Hg (15 in. Hg) vacuum is reached. *Do Not reverse direction of by-pass valve.* This will cause water to back up into the filter holder. If 380 mm Hg (15 in. Hg) is exceeded, either leak check at this higher vacuum or end the leak check as described below and start over.

When the leak check is completed, first slowly remove the plug from the inlet to the probe or filter holder and immediately turn off the vacuum pump. This prevents the water in the impingers from being forced backward into the filter holder (if placed before the impingers) and silica gel from being entrained backward into the third impinger.

Leak checks shall be conducted as described whenever the train is disengaged, e g. for silica gel or filter changes during the test, prior to each test run, and at the completion of each test run. If leaks are found to be in excess of the acceptable rate, the test will be considered invalid. To reduce lost time due to leakage occurrences, it is recommended that leak checks be conducted between port changes.

7 1 5 Particulate train operation—During the sampling run, an isokinetic sampling rate within 10%, or as specified by the Administrator, of true isokinetic shall be maintained.

For each run, record the data required on the example data sheet shown in Figure 13A–3 (Method 13A). Be sure to record the initial dry gas meter reading. Record the dry gas meter readings at the beginning and end of each sampling time increment, when changes in flow rates are made, and when sampling is halted. Take other data point readings at least once at each sample point during each time increment and additional readings when significant changes (20% variation in velocity head readings) neces-

...itate additional adjustments in flow rate. Be ...ure to level and zero the manometer.

Clean the portholes prior to the test run to minimize chance of sampling deposited material. To begin sampling, remove the ...ozzle cap, verify (if applicable) that the ...probe heater is working and filter heater is up to temperature, and that the pitot tube and probe are properly positioned. Position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. Nomographs are available for sampling trains using type S pitot tubes with 0.85 ± 0 02 (coefficients (C_p), and when sampling in air or a stack gas with equivalent density (molecular weight, M_d, equal to 29±4), which aid in the rapid adjustment of the isokinetic sampling rate without excessive computations. APTD-0576 details the procedure for using these nomographs. If C_p and M_d are outside the above stated ranges, do not use the nomograph unless appropriate steps are taken to compensate for the deviations.

When the stack is under significant negative pressure (height of impinger stem), take care to close the coarse adjust valve before inserting the probe into the stack to avoid water backing into the filter holder. If necessary, the pump may be turned on with the coarse adjust valve closed.

When the probe is in position, block off the openings around the probe and porthole to prevent unrepresentative dilution of the gas stream.

Traverse the stack cross section, as required by Method 1 or as specified by the Administrator, being careful not to bump the probe nozzle into the stack walls when sampling near the walls or when removing or inserting the probe through the portholes to minimize chance of extracting deposited material.

During the test run, make periodic adjustments to keep the probe and (if applicable) filter temperatures at their proper values. Add more ice and, if necessary, salt to the ice bath, to maintain a temperature of less than 20°C (68°F) at the impinger/silica gel outlet, to avoid excessive moisture losses. Also, periodically check the level and zero of the manometer.

If the pressure drop across the filter becomes high enough to make isokinetic sampling difficult to maintain, the filter may be replaced in the midst of a sample run. It is recommended that another complete filter assembly be used rather than attempting to change the filter itself. After the new filter or filter assembly is installed, conduct a leak check. The final emission results shall be based on the summation of all filter catches.

A single train shall be used for the entire sample run, except for filter and silica gel changes. However, if approved by the Administrator, two or more trains may be used for a single test run when there are two or more ducts or sampling ports. The final emission results shall be based on the total of all sampling train catches.

At the end of the sample run, turn off the pump, remove the probe and nozzle from the stack, and record the final dry gas meter reading. Perform a leak check.[1] Calculate percent isokinetic (see calculation section) to determine whether another test run should be made. If there is difficulty in maintaining isokinetic rates due to source conditions, consult with the Administrator for possible variance on the isokinetic rates.

[1] With acceptability of the test run to be based on the same criterion as in 7.1.4.

7 2 Sample recovery. Proper cleanup procedure begins as soon as the probe is removed from the stack at the end of the sampling period.

When the probe can be safely handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it to keep from losing part of the sample. Do not cap off the probe tip tightly while the sampling train is cooling down, as this would create a vacuum in the filter holder, thus drawing water from the impingers into the filter

Before moving the sample train to the cleanup site, remove the probe from the sample train, wipe off the silicone grease, and cap the open outlet of the probe. Be careful not to lose any condensate, if present. Wipe off the silicone grease from the filter inlet where the probe was fastened and cap it. Remove the umbilical cord from the last impinger and cap the impinger. After wiping off the silicone grease, cap off the filter holder outlet and impinger inlet. Ground glass stoppers, plastic caps, or serum caps may be used to close these openings.

Transfer the probe and filter-impinger assembly to the cleanup area. This area should be clean and protected from the wind so that the chances of contaminating or losing the sample will be minimized.

Inspect the train prior to and during disassembly and note any abnormal conditions. Using a graduated cylinder, measure and record the volume of the water in the first three impingers, to the nearest ml; any condensate in the probe should be included in this determination. Treat the samples as follows:

No. 71778, Pauley, J. E., 8-5-75

7.2.1 Container No. 1. Transfer the impinger water from the graduated cylinder to this container. Add the filter to this container. Wash all sample exposed surfaces, including the probe tip, probe, first three impingers, impinger connectors, filter holder, and graduated cylinder thoroughly with distilled water. Wash each component three separate times with water and clean the probe and nozzle with brushes. A maximum wash of 500 ml is used, and the washings are added to the sample container which must be made of polyethylene.

7.2.2 Container No. 2. Transfer the silica gel from the fourth impinger to this container and seal.

7.3 Analysis. Treat the contents of each sample container as described below.

7.3.1 Container No. 1.

7.3.1.1 Filter this container's contents, including the Whatman No 1 filter, through Whatman No. 541 filter paper, or equivalent into a 1500 ml beaker. NOTE: If filtrate volume exceeds 900 ml make filtrate basic with NaOH to phenolphthalein and evaporate to less than 900 ml.

7.3 1.2 Place the Whatman No. 541 filter containing the insoluble matter (including the Whatman No. 1 filter) in a nickel crucible, add a few ml of water and macerate the filter with a glass rod.

Add 100 mg CaO to the crucible and mix the contents thoroughly to form a slurry. Add a couple of drops of phenolphthalein indicator. The indicator will turn red in a basic medium. The slurry should remain basic during the evaporation of the water or fluoride ion will be lost. If the indicator turns colorless during the evaporation, an acidic condition is indicated. If this happens add CaO until the color turns red again.

Place the crucible in a hood under infrared lamps or on a hot plate at low heat. Evaporate the water completely.

After evaporation of the water, place the crucible on a hot plate under a hood and slowly increase the temperature until the paper chars. It may take several hours for complete charring of the filter to occur.

Place the crucible in a cold muffle furnace and gradually (to prevent smoking) increase the temperature to 600°C, and maintain until the contents are reduced to an ash. Remove the crucible from the furnace and allow it to cool.

7 3 1 3 Add approximately 4 g of crushed NaOH to the crucible and mix. Return the crucible to the muffle furnace, and fuse the sample for 10 minutes at 600°C.

Remove the sample from the furnace and cool to ambient temperature. Using several rinsings of warm distilled water transfer the contents of the crucible to the beaker containing the filtrate from container No 1 (7.3 1). To assure complete sample removal, rinse finally with two 20 ml portions of 25 percent (v/v) sulfuric acid and carefully add to the beaker. Mix well and transfer to a one-liter volumetric flask. Dilute to volume with distilled water and mix thoroughly. Allow any undissolved solids to settle.

7 3 2 Container No. 2. Weigh the spent silica gel and report to the nearest 0.5 g.

7 3.3 Adjustment of acid/water ratio in distillation flask—(Utilize a protective shield when carrying out this procedure). Place 400 ml of distilled water in the distilling flask and add 200 ml of concentrated H_2SO_4. Caution: Observe standard precautions when mixing the H_2SO_4 by slowly adding the acid to the flask with constant swirling. Add some soft glass beads and several small pieces of broken glass tubing and assemble the apparatus as shown in Figure 13A-2. Heat the flask until it reaches a temperature of 175°C to adjust the acid/water ratio for subsequent distillations. Discard the distillate.

7.3.4 Distillation—Cool the contents of the distillation flask to below 80°C. Pipette an aliquot of sample containing less than 0.6 mg F directly into the distilling flask and add distilled water to make a total volume of 220 ml added to the distilling flask. [For an estimate of what size aliquot does not exceed 0 6 mg F, select an aliquot of the solution and treat as described in Section 7 3.6. This will give an approximation of the fluoride content, but only an approximation since interfering ions have not been removed by the distillation step.]

Place a 250 ml volumetric flask at the condenser exist. Now begin distillation and gradually increase the heat and collect all the distillate up to 175°C. Caution: Heating the solution above 175°C will cause sulfuric acid to distill over.

The acid in the distilling flask can be used until there is carryover of interferences or poor fluoride recovery. An occasional check of fluoride recovery with standard solutions is advised. The acid should be changed whenever there is less than 90 percent recovery or blank values are higher than 0 1 ug/ml.

7.3.5 Determination of concentration—Bring the distillate in the 250 ml volumetric flask to the mark with distilled water and mix thoroughly. Pipette a 25 ml aliquot from the distillate. Add an equal volume of TISAB and mix. The sample should be at the same temperature as the calibration standards when measurements are made. If ambient lab temperature fluctuates more than ±2°C from the temperature at which the calibration standards were measured, condition samples and standards in a constant temperature bath measurement. Stir the sample with a magnetic stirrer during measurement to minimize electrode response

time If the stirrer generates enough heat to change solution temperature, place a piece of insulating material such as cork between the stirrer and the beaker. Dilute samples (below 10^{-4} M fluoride ion content) should be held in polyethylene or polypropylene beakers during measurement.

Insert the fluoride and reference electrodes into the solution. When a steady millivolt reading is obtained, record it This may take several minutes Determine concentration from the calibration curve Between electrode measurements, soak the fluoride sensing electrode in distilled water for 30 seconds and then remove and blot dry.

8 *Calibration.*

Maintain a laboratory log of all calibrations.

8 1 Sampling Train

8 1 1 Probe nozzle—Using a micrometer, measure the inside diameter of the nozzle to the nearest 0 025 mm (0 001 in.) Make 3 separate measurements using different diameters each time and obtain the average of the measurements. The difference between the high and low numbers shall not exceed 0.1 mm (0 004 in.).

When nozzles become nicked, dented, or corroded, they shall be reshaped, sharpened, and recalibrated before use.

Each nozzle shall be permanently and uniquely identified.

8.1.2 Pitot tube—The pitot tube shall be calibrated according to the procedure outlined in Method 2.

8.1.3 Dry gas meter and orifice meter. Both meters shall be calibrated according to the procedure outlined in APTD–0576. When diaphragm pumps with by-pass valves are used, check for proper metering system design by calibrating the dry gas meter at an additional flow rate of 0 0057 m^3/min. (0 2 cfm) with the by-pass valve fully opened and then with it fully closed If there is more than ±2 percent difference in flow rates when compared to the fully closed position of the by-pass valve, the system is not designed properly and must be corrected.

8.1 4 Probe heater calibration—The probe heating system shall be calibrated according to the procedure contained in APTD–0576. Probes constructed according to APTD–0581 need not be calibrated if the calibration curves in APTD–0576 are used.

8 1.5 Temperature gauges—Calibrate dial and liquid filled bulb thermometers against mercury-in-glass thermometers. Thermocouples need not be calibrated For other devices, check with the Administrator.

8 2 Analytical Apparatus

8 2.1 Fluoride Electrode—Prepare fluoride standardizing solutions by serial dilution of the 0.1 M fluoride standard solution Pipet 10 ml of 0 1 M NaF into a 100 ml volumetric flask and make up to the mark with distilled water for a 10^{-2} M standard solution. Use 10 ml of 10^{-2} M solution to make a 10^{-3} M solution in the same manner Reapt 10^{-4} and 10^{-5} M solutions.

Pipet 50 ml of each standard into a separate beaker. Add 50 ml of TISAB to each beaker. Place the electrode in the most dilute standard solution. When a steady millivolt reading is obtained, plot the value on the linear axis of semi-log graph paper versus concentration on the log axis. Plot the nominal value for concentration of the standard on the log axis, e g., when 50 ml of 10^{-2} M standard is diluted with 50 ml TISAB, the concentration is still designated "10^{-2} M".

Between measurements soak the fluoride sensing electrode in distilled water for 30 seconds, and then remove and blot dry. Analyze the standards going from dilute to concentrated standards. A straight-line calibration curve will be obtained, with nominal concentrations of $10f^1$, $10f^2$, 10^{-3}, 10^{-2}, 10^{-1} concentrations of 10^{-3}, 10^{-4}, 10^{-1}, 10^{-2}, 10^{-1} concentrations of 10^{-5}, 10^{-4}, 10^{-1}, $10f^2$, $10f^1$ fluoride molarity on the log axis plotted versus electrode potential (in millivolts) on the linear scale.

Calibrate the fluoride electrode daily, and check it hourly. Prepare fresh fluoride standardizing solutions daily of 10^{-2} M or less. Store fluoride standardizing solutions in polyethylene or polypropylene containers. (Note: Certain specific ion meters have been designed specifically for fluoride electrode use and give a direct readout of fluoride ion concentration. These meters may be used in lieu of calibration curves for fluoride measurements over narrow concentration ranges. Calibrate the meter according to manufacturer's instructions.)

9. *Calculations.*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

9.1 Nomenclature.

A_n = Cross sectional area of nozzle, m^2 (ft^2).

A_t = Aliquot of total sample added to still, ml.

B_{ws} = Water vapor in the gas stream, proportion by volume.

C_s = Concentration of fluoride in stack gas, mg/m^3, corrected to standard conditions of 20° C, 760 mm Hg (68° F, 29.92 in. Hg) on dry basis.

F_t = Total weight of fluoride in sample, mg.

I = Percent of isokinetic sampling.

M = Concentration of fluoride from calibration curve, molarity.

m_n = Total amount of particulate matter collected, mg.

M_w = Molecular weight of water, 18 g/g-mole (18 lb/lb-mole).

m_a = Mass of residue of acetone after evaporation, mg.

P_{bar} = Barometric pressure at the sampling site, mm Hg (in. Hg).

P_s = Absolute stack gas pressure, mm Hg (in. Hg).

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R = Ideal gas constant, 0 06236 mm Hg-m^3/°K-g-mole (21.83 in. Hg-ft^3/°R-lb-mole).

T_m = Absolute average dry gas meter temperature (see fig. 13A-3), °K (°R).

T_s = Absolute average stack gas temperature (see fig. 13A-3), °K (°R).

T_{std} = Standard absolute temperature, 293° K (528° R).

V_a = Volume of acetone blank, ml.

V_{aw} = Volume of acetone used in wash, ml.

V_d = Volume of distillate collected, ml.

V_{lc} = Total volume of liquid collected in impingers and silica gel, ml. Volume of water in silica gel equals silica gel weight increase in grams times 1 ml/gram. Volume of liquid collected in impinger equals final volume minus initial volume.

V_m = Volume of gas sample as measured by dry gas meter, dcm (dcf).

$V_{m(std)}$ = Volume of gas sample measured by the dry gas meter corrected to standard conditions, dscm (dscf).

$V_{w(std)}$ = Volume of water vapor in the gas sample corrected to standard conditions, scm (scf).

V_t = Total volume of sample, ml.

v_s = Stack gas velocity, calculated by Method 2, Equation 2–7 using data obtained from Method 5, m/sec (ft/sec).

W_a = Weight of residue in acetone wash, mg.

ΔH = Average pressure differential across the orifice (see fig. 13A–3), meter, mm H_2O (in H_2O).

ρ_a = Density of acetone, mg/ml (see label on bottle).

ρ_w = Density of water, 1 g/ml (0.00220 lb/ml).

θ = Total sampling time, min.

13.6 = Specific gravity of mercury.

60 = Sec/min.

100 = Conversion to percent.

9.2 Average dry gas meter temperature and average orifice pressure drop. See data sheet (Figure 13A–3 of Method 13A).

9 3 Dry gas volume. Use Section 9.3 of Method 13A.

9 4 Volume of Water Vapor. Use Section 9 4 of Method 13A.

9 5 Moisture Content. Use Section 9.5 of Method 13A.

9 6 Concentration

9 6 1 Calculate the amount of fluoride in the sample according to equation 13B-1.

$$F_t = K - (V_a)\ (M)\ \frac{V_t}{A_t}$$

where:

K = 19 mg/ml.

9.6 2 Concentration of fluoride in stack gas. Use Section 9 6 2 of Method 13A.

9 7 Isokinetic variation. Use Section 9.7 of Method 13A.

9 8 Acceptable results. Use Section 9.8 of Method 13A

10. *References.*

Bellack, Ervin, "Simplified Fluoride Distillation Method," *Journal of the American Water Works Association* #50: 530–6 (1958).

MacLeod, Kathryn E, and Howard L. Crist, "Comparison of the SPADNS—Zirconium Lake and Specific Ion Electrode Methods of Fluoride Determination in Stack Emission Samples," *Analytical Chemistry* 45: 1272–1273 (1973).

Martin, Robert M. "Construction Details of Isokinetic Source Sampling Equipment," Environmental Protection Agency, Air Pollution Control Office Publication No. APTD–0581

1973 Annual Book of ASTM Standards, Part 23, Designation: D 1179–72.

Pom, Jerome J., "Maintenance, Calibration, and Operation of Isokinetic Source Sampling Equipment," Environmental Protection Agency, Air Pollution Control Office Publication No APTD–0576.

Standard Methods for the Examination of Water and Waste Water, published jointly by American Public Health Association, American Water Works Association and Water Pollution Control Federation, 13th Edition (1971).

(Sections 111 and 114 of the Clean Air Act, as amended by section 4(a) of Pub. L. 91–604, 84 Stat. 1678 (42 U.S C. 1857 c–6, c–9))

[FR Doc.75–20478 Filed 8–5–75;8:45 am]

15

[FRL 428-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegations of Authority to State of California on Behalf of Bay Area, Monterey Bay Unified, Humboldt County and Del Norte County Air Pollution Control Districts

Pursuant to the delegations of authority for the standards of performance for new stationary sources (NSPS) to the State of California on behalf of the Bay Area and Monterey Bay Unified Air Pollution Control Districts (dated May 23, 1975), and on behalf of the Humboldt County and Del Norte County Air Pollution Control Districts (dated July 10, 1975), EPA is today amending 40 CFR 60.4, Address, to reflect these delegations. Notices announcing these delegations are published today in the Notices Section of this issue. The amended § 60.4 is set forth below. It adds the addresses of the Bay Area, Monterey Bay Unified, Humboldt County and Del Norte County Air Pollution Control Districts, to which must be addressed all reports, requests, applications, submittals, and communications pursuant to this part by sources subject to the NSPS located within these Air Pollution Control Districts.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegations which are reflected by this administrative amendment were effective on May 23, 1975 (Bay Area and Monterey Bay Districts) and on July 10, 1975 (Humboldt County and Del Norte County Districts) and it serves no purpose to delay the technical change of this addition of the Air Pollution Control District addresses to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of section 111 of the Clean Air Act, as amended. 42 U.S.C. 1857c-6.

Dated: September 6, 1975.

STANLEY W. LEGRO,
Assistant Administrator for Enforcement.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4, paragraph (b) is amended by revising subparagraph (F), to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)-(E) * * *

(F) California

Bay Area Air Pollution Control District, 939 Ellis St., San Francisco, CA 94109.

Del Norte County Air Pollution Control District, 5600 S. Broadway, Eureka, CA 95501.

Humboldt County Air Pollution Control District, 5600 S. Broadway, Eureka, CA 95501.

Monterey Bay Unified Air Pollution Control District, 420 Church St. (P.O. Box 487), Salinas, CA 93901.

* * * * *

[FR Doc.75-24202 Filed 9-10-75;8:45 am]

FEDERAL REGISTER, VOL. 40, NO. 177-

-THURSDAY, SEPTEMBER 11, 1975

16 Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 407-3]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Electric Arc Furnaces in the Steel Industry

On October 21, 1974 (39 FR 37466), under section 111 of the Clean Air Act, as amended, the Environmental Protection Agency (EPA) proposed standards of performance for new and modified electric arc furnaces in the steel industry. Interested persons participated in the rulemaking by submitting written comments to EPA. A total of 19 comment letters was received, seven of which came from the industry, eight from State and local air pollution control agencies, and four from Federal agencies. The Freedom of Information Center, Room 202 West Tower, 401 M Street, S.W., Washington, D.C., has copies of the comment letters received and a summary of the issues and Agency responses available for public inspection. In addition, copies of the issue summary and Agency responses may be obtained upon written request from the EPA Public Information Center (PM-215), 401 M Street, S.W., Washington, D.C. 20460 (specify—Public Comment Summary: Electric Arc Furnaces in the Steel Industry). The comments have been carefully considered, and where determined by the Administrator to be appropriate, changes have been made to the proposed regulation and are incorporated in the regulation promulgated herein.

The bases for the proposed standards are presented in "Background Information for Standards of Performance: Electric Arc Furnaces in the Steel Industry," (EPA-450/2-74-017a, b). Copies of this document are available on request from the Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711, Attention: Mr. Don R. Goodwin.

Summary of Regulation

The promulgated standards of performance for new and modified electric arc furnaces in the steel industry limit particulate matter emissions from the control device, from the shop, and from the dust-handling equipment. Emissions from the control device are limited to less than 12 mg/dscm (0.0052 gr/dscf) and 3 percent opacity. Furnace emissions escaping capture by the collection system and exiting from the shop are limited to zero percent opacity, but emissions greater than this level are allowed during charging periods and tapping periods. Emissions from the dust-handling equipment are limited to less than 10 percent opacity. The regulation requires monitoring of flow rates through each separately ducted emission capture hood and monitoring of the pressure inside the electric arc furnace for direct shell evacuation systems. Additionally, continuous monitoring of opacity of emissions from the control device is required.

Significant Comments and Changes Made to the Proposed Regulation

All of the comment letters received by EPA contained multiple comments. The most significant comments and the differences between the proposed and promulgated regulations are discussed below. In addition to the discussed changes, a number of paragraphs and sections of the proposed regulation were reorganized in the regulation promulgated herein.

(1) *Applicability.* One commentator questioned whether electric arc furnaces that use continuous feeding of prereduced ore pellets as the primary source of iron can comply with the proposed standards of performance since the standards were based on data from conventionally charged furnaces. Electric arc furnaces that use prereduced ore pellets were not investigated by EPA because this process was still being researched by the steel industry during development of the standard and was several years from extensive use on commercial sized furnaces. Emissions from this type of furnace are generated at different rates and in different amounts over the steel production cycle than emissions from conventionally charged furnaces. The proposed standards were structured for the emission cycle of a conventionally charged electric arc furnace. The standards, consequently, are not suitable for application to electric arc furnaces that use prereduced ore pellets as the primary source of iron. Even with use of best available control technology, emissions from these furnaces may not be controllable to the level of all of the standards promulgated herein; however, over the entire cycle the emissions may be less than those from a well-controlled conventional electric arc furnace. Therefore, EPA believes that standards of performance for electric arc furnaces using prereduced ore pellets require a different structure than do standards for conventionally charged furnaces. An investigation into the emission reduction achievable and best available control technology for these furnaces will be conducted in the future and standards of performance will be established. Consequently, electric arc furnaces that use continuous feeding of prereduced ore pellets as the primary source of iron are not subject to the requirements of this subpart.

(2) *Concentration standard for emissions from the control device.* Four commentators recommended revising the concentration standard for the control device effluent to 18 mg/dscm (0.008 gr/dscf) from the proposed level of 12 mg/dscm (0.0052 gr/dscf). The argument for the higher standard was that the proposed standard had not been demonstrated on either carbon steel shops or on combination direct shell evacuation-canopy hood control systems. Emission measurement data presented in "Background Information for Standards of Performance: Electric Arc Furnaces in the Steel Industry" show that carbon steel shops as well as alloy steel shops can reduce particulate matter emissions to less than 12 mg/dscm by application of well-designed fabric filter collectors. These data also show that combination direct shell evacuation-canopy hood systems can control emission levels to less than 12 mg/dscm. EPA believes that revising the standard to 18 mg/dscm would allow relaxation of the design requirements of the fabric filter collectors which are installed to meet the standard. Accordingly, the standard promulgated herein limits particulate matter emissions from the control device to less than 12 mg/dscm.

Two commentators requested that specific concentration and opacity standards be established for emissions from scrubber controlled direct shell evacuation systems. The argument for a separate concentration standard was that emissions from scrubber controlled direct shell evacuation systems can be reduced to only about 50 mg/dscm (0.022 gr/dscf) and, thus, even with the proposed proration provisions under § 60.274(b), it is not possible to use scrubbers and comply with the proposed concentration standard. The commentators also argued that a separate opacity standard was necessary for scrubber equipped systems because the effluent is more concentrated and, thus, reflects and scatters more visible light than the effluent from fabric filter collectors.

EPA would like to emphasize that use of venturi scrubbers to control the effluent from direct shell evacuation systems is not considered to be a "best system of emission reduction considering costs." The promulgated standards of performance for electric arc furnaces reflect the degree of emission reduction achievable for systems discharging emissions through fabric filter collectors. EPA believes, however, that the regulation does not preclude use of control systems that discharge direct shell evacuation system emissions through venturi scrubbers. Available information indicates that effluent from a direct shell evacuation system can be controlled to 0.01 gr/dscf or less using a high energy venturi scrubber (pressure drop greater than 60 in. w.g.). If the scrubber reduces particulate matter emissions to 0.01 gr/dscf, then the fabric filter collector is only required to reduce the emissions from the canopy hood to about 0.004 gr/dscf in order for the emission rates to be less than 0.0052 gr/dscf. Therefore, it is technically feasible for a facility to use a high energy scrubber and a fabric filter to control the combined furnace emissions to less than 0.0052 gr/dscf. A concentration standard of 0.022 gr/dscf for scrubbers would not require installation of control devices which have a collection efficiency comparable to that of best control technology (well-designed and well-operated fabric filter collector). In addition, electric arc furnace particulate matter emissions are invisible to the human eye at effluent concentrations less than 0.01 gr/dscf

when emitted from average diameter stacks. For the reasons discussed above, neither a separate concentration standard nor a separate opacity standard will be established as suggested by the commentators.

(3) *Control device opacity standard.* Four commentators suggested that the proposed control device opacity standard either be revised from less than five percent opacity to less than ten percent opacity based on six-minute average values or that a time exemption be provided for visible emissions during the cleaning cycle of shaker-type fabric filter collectors.

EPA's experience indicates that a time exemption to allow for puffing during the cleaning cycle of the fabric filter collector is not necessary. For this application, a well-designed and well-maintained fabric filter collector should have no visible emissions during all phases of the operating cycle. The promulgated opacity standard, therefore, does not provide a time exemption for puffing of the collector during the cleaning cycle.

The suggested revision of the proposed opacity standard to ten percent (based on six-minute average values) was considered in light of recent changes in Method 9 of Appendix A to this part (39 FR 39872). The revisions to Method 9 require that compliance with opacity standards be determined by averaging sets of 24 consecutive observations taken at 15-second intervals (six-minute averages). All six-minute average values of the opacity data used as the basis for the proposed opacity standard are zero percent. EPA believes that the ten percent standard suggested by the commentators would allow much less effective operation and maintenance of the control device than is required by the concentration standard. On the basis of available data, a five percent opacity standard (based on six-minute average values) also is unnecessarily lenient.

The proposed opacity standard of zero percent was revised slightly upward to be consistent with previously established opacity standards which are less stringent than their associated concentration standards without being unduly lax. The promulgated opacity standard limits emissions from the control device to less than three percent opacity (based on averaging sets of 24 consecutive observations taken at 15-second intervals). Use of six-minute average values to determine compliance with applicable opacity standards makes opacity levels of any value possible, instead of the previous method's limitation of values at discrete intervals of five percent opacity.

(4) *Standards on emissions from the shop.* Twelve commentators questioned the value of the shop opacity standards, arguing that the proposed standards are unenforceable, too lenient, or too stringent.

Commentators arguing for less stringent or more stringent standards suggested various alternative opacity values for the charging or tapping period standards, different averaging periods, and a different limitation on emissions from the shop during the meltdown and refining period of the EAF operation. Because of these comments, the basis for these standards was thoroughly reevaluated, including a review of all available data and follow-up contacts with commentators who had offered suggestions. The follow-up contacts revealed that the suggested revisions were opinions only and were not based on actual data. The reevaluation of the data bases of the proposed standards reaffirmed that the standards represented levels of emission control achievable by application of best control technology considering costs. Hence, EPA concluded that the standards are reasonable (neither too stringent nor too lenient) and that revision of these standards is not warranted in the absence of specific information indicating such a need.

Four commentators believed that the proposed standards were impractical to enforce for the following reasons:

(1) Intermingling of emissions from non-regulated sources with emissions from the electric arc furnaces would make enforcement of the standards impossible.

(2) Overlap of operations at multi-furnace shops would make it difficult to identify the periods in which the charging and tapping standards are applicable.

(3) Additional manpower would be required in order to enforce these standards.

(4) The standards would require access to the shop, providing the source with notice of surveillance and the results would not be representative of routine emissions.

(5) The standards would be unenforceable at facilities with a mixture of existing and new electric arc furnaces in the same shop.

EPA considered all of the comments on the enforceability of the proposed standards and concluded that some changes were appropriate. The proposed regulation was reconsidered with the intent of developing more enforceable provisions requiring the same level of control. This effort resulted in several changes to the regulation, which are discussed below.

The promulgated regulation retains the proposed limitations on the opacity of emissions exiting from the shop except for the exemption of one minute/hour per EAF during the refining and meltdown periods. The purpose of this exemption was to provide some allowance for puffs due to "cave-ins" or addition of iron ore or burnt lime through the slag door. Only one suspected "cave-in" and no puffs due to additions occurred during 15 hours of observations at a well-controlled facility; therefore, it was concluded that these brief uncontrolled puffs do not occur frequently and whether or not a "cave-in" has occurred is best evaluated on a case-by-case basis. This approach was also necessitated by recent revisions to Method 9 (39 FR 39872) which require basing compliance on six-minute averages of the observations. Use of six-minute averages of opacity readings is not consistent with allowing a time exemption. Determination of whether brief puffs of emissions occurring during refining and meltdown periods are due to "cave-ins" will be made at the time of determination of compliance. If such emissions are considered to be due to a "cave-in" or other uncontrollable event, the evaluation may be repeated without any change in operating conditions.

The purpose of the proposed opacity standards limiting the opacity of emissions from the shop was to require good capture of the furnace emissions. The method for routinely enforcing these capture requirements has been revised in the regulation promulgated herein in that the owner or operator is now required to demonstrate compliance with the shop opacity standards just prior to conducting the performance test on the control device. This performance evaluation will establish the baseline operating flow rates for each of the canopy hoods or other fume capture hoods and the furnace pressures for the electric arc furnace using direct shell evacuation systems. Continuous monitoring of the flow rate through each separately ducted control system is required for each electric arc furnace subject to this regulation. Owners or operators of electric arc furnaces that use a direct shell evacuation system to collect the refining and meltdown period emissions are required to continuously monitor the pressure inside the furnace free space. The flow rate and pressure data will provide a continuous record of the operation of the control systems. Facilities that use a building evacuation system for capture and control of emissions are not subject to the flow rate and pressure monitoring requirements if the building roof is never opened.

The shop opacity standards promulgated herein are applicable only during demonstrations of compliance of the affected facility. At all other times the operating conditions must be maintained at the baseline values or better. Use of operating conditions that will result in poorer capture of emissions constitutes unacceptable operation and maintenance of the affected facility. These provisions of the promulgated regulation will allow evaluation of the performance of the collection system without interference from other emission sources because the non-regulated sources can be shut down for the duration of the evaluation. The monitoring of operations requirements will simplify enforcement of the regulation because neither the enforcing agency nor the owner or operator must show that any apparent violation was or was not due to operation of non-regulated sources.

The promulgated regulation's monitoring of operation requirements will add negligible additional costs to the total cost of complying with the promulgated standards of performance. Flow rate monitoring devices of sufficient accuracy to meet the requirements of § 60.274(b) can be installed for $600–$4000 depending on the flow profile of the area being monitored and the complexity of the monitoring device. Devices that monitor

the pressure inside the free space of an electric arc furnace equipped with a direct shell evacuation system are installed by most owners or operators in order to obtain better control of the furnace operation. Consequently, for most owners or operators, the pressure monitoring requirements will only result in the additional costs for installation and operation of a strip chart recorder. A suitable strip chart recorder can be installed for less than $600.

There are no data reduction requirements in the flow rate monitoring provisions. The pressure monitoring provisions for the direct shell evacuation control systems require recording of the pressures as 15-minute integrated averages. The pressure inside the electric arc furnace above the slag and metal fluctuates rapidly. Integration of the data over 15-minute periods is necessary to provide an indication of the operation of the system. Electronic and mechanical integrators are available at an initial cost of less than $600 to accomplish this task. Electronic circuits to produce a continuous integration of the data can be built directly into the monitoring device or can be provided as a separate modular component of the monitoring system. These devices can provide a continuous integrated average on a strip chart recorder.

(5) *Emission monitoring.* Three commentators suggested deletion of the proposed opacity monitoring requirements because long path lengths and multiple compartments in pressurized fabric filter collectors make monitoring infeasible. The proposed opacity monitoring requirements have not been deleted because opacity monitoring is feasible on the control systems of interest (closed or suction fabric filter collectors). This subpart also permits use of alternative control systems which are not amenable to testing and monitoring using existing procedures, providing the owner or operator can demonstrate compliance by alternative methods. If the owner or operator plans to install a pressurized fabric filter collector, he should submit for the Administrator's approval the emission testing procedures and the method of monitoring the emissions of the collector. The opacity of emissions from pressurized fabric filter collectors can be monitored using present instrumentation at a reasonable cost. Possible alternative methods for monitoring of emissions from pressurized fabric filter collectors include: (1) monitoring of several compartments by a conventional path length transmissometer and rotation of the transmissometer to other groups of collector compartments on a scheduled basis or (2) monitoring with several conventional path length transmissometers. In addition to monitoring schemes based on conventional path length transmissometers, a long path transmissometer could be used to monitor emissions from a pressurized fabric filter collector. Transmissometers capable of monitoring distances up to 150 meters are commercially available and have been demonstrated to accurately monitor opacity. Use of long path transmissometers on pressurized fabric filter collectors has yet to be demonstrated, but if properly installed there is no reason to believe that the transmissometer will not accurately and representatively monitor emissions. The best location for a long path transmissometer on a fabric filter collector will depend on the specific design features of both; therefore, the best location and monitoring procedure must be established on an individual basis and is subject to the Administrator's approval.

Two commentators argued that the proposed reporting requirements would result in excessive paperwork for the owner or operator. These commentators suggested basing the reporting requirements on hourly averages of the monitoring data. EPA believes that one-hour averaging periods would not produce values that would meaningfully relate to the operation of the fabric filter collector and would not be useful for comparison with Method 9 observations. In light of the revision of Method 9 to base compliance on six-minute averages, all six-minute periods in which the average opacity is three percent or greater shall be reported as periods of excess emissions. EPA does not believe that this requirement will result in an excessive burden for properly operated and maintained facilities.

(6) *Test methods and procedures.* Two commentators questioned the precision and accuracy of Method 5 of Appendix A to this part when applied to gas streams with particulate matter concentrations less than 12 mg/dscm. EPA has reviewed the sampling and analytical error associated with Method 5 testing of low concentration gas streams. It was concluded that if the recommended minimum sample volume (160 dscf) is used, then the errors should be within the acceptable range for the method. Accordingly, the recommended minimum sample volumes and times of the proposed regulation are being promulgated unchanged.

Three commentators questioned what methodology was to be used in testing of open or pressurized fabric filter collectors. These commentators advocated that EPA develop a reference test method for testing of pressurized fabric filter collectors. From EPA's experience, development of a single test procedure for representative sampling of all pressurized fabric filter collectors is not feasible because of significant variations in the design of these control devices. Test procedures for demonstrating compliance with the standard, however, can be developed on a case-by-case basis. The promulgated regulation does require that the owner or operator design and construct the control device so that representative measurement of the particulate matter emissions is feasible.

Provisions in 40 CFR 60.8(b) allow the owner or operator upon approval by the Administrator to show compliance with the standard of performance by use of an "equivalent" test method or "alternative" test method. For pressurized fabric filter collectors, the owner or operator is responsible for development of an "alternative" or "equivalent" test procedure which must be approved prior to the determination of compliance.

Depending on the design of the pressurized fabric filter collector, the performance test may require use of an "alternative" method which would produce results adequate to demonstrate compliance. An "alternative" method does not necessarily require that the effluent be discharged through a stack. A possible alternative procedure for testing is representative sampling of emissions from a randomly selected, representative number of compartments of the collector. If the flow rate of effluent from the compartments or other conditions are not amenable to isokinetic sampling, then subisokinetic sampling (that is, sampling at lower velocities than the gas stream velocity, thus biasing the sample toward collection of a greater concentration than is actually present) should be used. If a suitable "equivalent" or "alternative" test procedure is not developed by the owner or operator, then total enclosure of the collector and testing by Method 5 of Appendix A to this part is required.

A new paragraph has been added to clarify that during emission testing of pressurized fabric filter collectors the dilution air vents must be blocked off for the period of testing or the amount of dilution must be determined and a correction applied in order to accurately determine the emission rate of the control device. The need for dilution air correction was discussed in "Background Information for Standards of Performance: Electric Arc Furnaces in the Steel Industry" but was not an explicit requirement in the proposed regulation.

(7) *Miscellaneous.* Some commentators on the proposed standards of performance for ferroalloy production facilities (39 FR 37470) questioned the rationale for the differences between the electric arc furnace regulation and the ferroalloy production facilities regulation with respect to methods of limiting fugitive emissions. The intent of both regulations is to require effective capture and control of emissions from the source. The standards of performance for electric arc furnaces regulate collection efficiency by placing limitations on the opacity of emissions from the shop. The performance of the control system is evaluated at the shop roof and/or other areas of emission to the atmosphere because it is not possible to evaluate the performance of the collection system inside the shop. In electric arc furnace shops, collection systems for capture of charging and tapping period emissions must be located at least 30 or 40 feet above the furnace to allow free movement of the crane which charges raw materials to the furnace. Fumes from charging, tapping, and other activities rise and accumulate in the upper areas of the building, thus obscuring visibility. Because of the poor visibility within the shop, the performance of the emission collection system can only be evaluated at the point where emissions are discharged to the atmosphere. Ferroalloy electric submerged arc fur-

nace operations do not require this large free space between the furnace and the collection device (hood). Visibility around the electric submerged arc furnace is good. Consequently, the performance of the collection device on a ferroalloy furnace may be evaluated at the collection area rather than at the point of discharge to the atmosphere.

Effective date. In accordance with section 111 of the Act, these regulations prescribing standards of performance for electric arc furnaces in the steel industry are effective on September 23, 1975, and apply to electric arc furnaces and their associated dust-handling equipment, the construction or modification of which was commenced after October 21, 1974.

Dated: September 15, 1975.

JOHN QUARLES,
Acting Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. The table of sections is amended by adding subpart AA as follows:

* * * * *

Subpart AA—Standards of Performance for Steel Plants: Electric Arc Furnaces

60.270 Applicability and designation of affected facility.
60.271 Definitions.
60.272 Standard for particulate matter.
60.273 Emission monitoring.
60.274 Monitoring of operations.
60.275 Test methods and procedures.

* * * * *

2. Part 60 is amended by adding subpart AA as follows:

* * * * *

Subpart AA—Standards of Performance for Steel Plants: Electric Arc Furnaces

§ 60.270 Applicability and designation of affected facility.

The provisions of this subpart are applicable to the following affected facilities in steel plants: electric arc furnaces and dust-handling equipment.

§ 60.271 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Electric arc furnace" (EAF) means any furnace that produces molten steel and heats the charge materials with electric arcs from carbon electrodes. Furnaces from which the molten steel is cast into the shape of finished products, such as in a foundry, are not affected facilities included within the scope of this definition. Furnaces which, as the primary source of iron, continuously feed prereduced ore pellets are not affected facilities within the scope of this definition.

(b) "Dust-handling equipment" means any equipment used to handle particulate matter collected by the control device and located at or near the control device for an EAF subject to this subpart.

(c) "Control device" means the air pollution control equipment used to remove particulate matter generated by an EAF(s) from the effluent gas stream.

(d) "Capture system" means the equipment (including ducts, hoods, fans, dampers, etc.) used to capture or transport particulate matter generated by an EAF to the air pollution control device.

(e) "Charge" means the addition of iron and steel scrap or other materials into the top of an electric arc furnace.

(f) "Charging period" means the time period commencing at the moment an EAF starts to open and ending either three minutes after the EAF roof is returned to its closed position or six minutes after commencement of opening of the roof, whichever is longer.

(g) "Tap" means the pouring of molten steel from an EAF.

(h) "Tapping period" means the time period commencing at the moment an EAF begins to tilt to pour and ending either three minutes after an EAF returns to an upright position or six minutes after commencing to tilt, whichever is longer.

(i) "Meltdown and refining" means that phase of the steel production cycle when charge material is melted and undesirable elements are removed from the metal.

(j) "Meltdown and refining period" means the time period commencing at the termination of the initial charging period and ending at the initiation of the tapping period, excluding any intermediate charging periods.

(k) "Shop opacity" means the arithmetic average of 24 or more opacity observations of emissions from the shop taken in accordance with Method 9 of Appendix A of this part for the applicable time periods.

(l) "Heat time" means the period commencing when scrap is charged to an empty EAF and terminating when the EAF tap is completed.

(m) "Shop" means the building which houses one or more EAF's.

(n) "Direct shell evacuation system" means any system that maintains a negative pressure within the EAF above the slag or metal and ducts these emissions to the control device.

§ 60.272 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from an electric arc furnace any gases which:

(1) Exit from a control device and contain particulate matter in excess of 12 mg/dscm (0.0052 gr/dscf).

(2) Exit from a control device and exhibit three percent opacity or greater.

(3) Exit from a shop and, due solely to operations of any EAF(s), exhibit greater than zero percent shop opacity except:

(i) Shop opacity greater than zero percent, but less than 20 percent, may occur during charging periods.

(ii) Shop opacity greater than zero percent, but less than 40 percent, may occur during tapping periods.

(iii) Opacity standards under paragraph (a)(3) of this section shall apply only during periods when flow rates and pressures are being established under § 60.274 (c) and (f).

(iv) Where the capture system is operated such that the roof of the shop is closed during the charge and the tap, and emissions to the atmosphere are prevented until the roof is opened after completion of the charge or tap, the shop opacity standards under paragraph (a)(3) of this section shall apply when the roof is opened and shall continue to apply for the length of time defined by the charging and/or tapping periods.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from dust-handling equipment any gases which exhibit 10 percent opacity or greater.

§ 60.273 Emission monitoring.

(a) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the control device(s) shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart.

(b) For the purpose of reports under § 60.7(c), periods of excess emissions that shall be reported are defined as all six-minute periods during which the average opacity is three percent or greater.

§ 60.274 Monitoring of operations.

(a) The owner or operator subject to the provisions of this subpart shall maintain records daily of the following information:

(1) Time and duration of each charge;

(2) Time and duration of each tap;

(3) All flow rate data obtained under paragraph (b) of this section, or equivalent obtained under paragraph (d) of this section; and

(4) All pressure data obtained under paragraph (e) of this section.

(b) Except as provided under paragraph (d) of this section, the owner or operator subject to the provisions of this subpart shall install, calibrate, and maintain a monitoring device that continously records the volumetric flow rate through each separately ducted hood. The monitoring device(s) may be installed in any appropriate location in the exhaust duct such that reproducible flow rate monitoring will result. The flow rate monitoring device(s) shall have an accuracy of ±10 percent over its normal operating range and shall be calibrated according to the manufacturer's instructions. The Administrator may require the owner or operator to demonstrate the accuracy of the monitoring device(s) relative to Methods 1 and 2 of Appendix A of this part.

(c) When the owner or operator of an EAF is required to demonstrate compliance with the standard under § 60.272 (a)(3) and at any other time the Administrator may require (under section 114 of the Act, as amended), the volu-

metric flow rate through each separately ducted hood shall be determined during all periods in which the hood is operated for the purpose of capturing emissions from the EAF using the monitoring device under paragraph (b) of this section. The owner or operator may petition the Administrator for reestablishment of these flow rates whenever the owner or operator can demonstrate to the Administrator's satisfaction that the EAF operating conditions upon which the flow rates were previously established are no longer applicable. The flow rates determined during the most recent demonstration of compliance shall be maintained (or may be exceeded) at the appropriate level for each applicable period. Operation at lower flow rates may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility.

(d) The owner or operator may petition the Administrator to approve any alternative method that will provide a continuous record of operation of each emission capture system.

(e) Where emissions during any phase of the heat time are controlled by use of a direct shell evacuation system, the owner or operator shall install, calibrate, and maintain a monitoring device that continuously records the pressure in the free space inside the EAF. The pressure shall be recorded as 15-minute integrated averages. The monitoring device may be installed in any appropriate location in the EAF such that reproducible results will be obtained. The pressure monitoring device shall have an accuracy of ±5 mm of water gauge over its normal operating range and shall be calibrated according to the manufacturer's instructions.

(f) When the owner or operator of an EAF is required to demonstrate compliance with the standard under § 60.272 (a)(3) and at any other time the Administrator may require (under section 114 of the Act, as amended), the pressure in the free space inside the furnace shall be determined during the meltdown and refining period(s) using the monitoring device under paragraph (e) of this section. The owner or operator may petition the Administrator for reestablishment of the 15-minute integrated average pressure whenever the owner or operator can demonstrate to the Administrator's satisfaction that the EAF operating conditions upon which the pressures were previously established are no longer applicable. The pressure determined during the most recent demonstration of compliance shall be maintained at all times the EAF is operating in a meltdown and refining period. Operation at higher pressures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility.

(g) Where the capture system is designed and operated such that all emissions are captured and ducted to a control device, the owner or operator shall not be subject to the requirements of this section.

§ 60.275 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided under § 60.8(b), shall be used to determine compliance with the standards prescribed under § 60.272 as follows:

(1) Method 5 for concentration of particulate matter and associated moisture content;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling time for each run shall be at least four hours. When a single EAF is sampled, the sampling time for each run shall also include an integral number of heats. Shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator. The minimum sample volume shall be 4.5 dscm (160 dscf).

(c) For the purpose of this subpart, the owner or operator shall conduct the demonstration of compliance with 60.272(a)(3) and furnish the Administrator a written report of the results of the test.

(d) During any performance test required under § 60.8 of this part, no gaseous diluents may be added to the effluent gas stream after the fabric in any pressurized fabric filter collector, unless the amount of dilution is separately determined and considered in the determination of emissions.

(e) When more than one control device serves the EAF(s) being tested, the concentration of particulate matter shall be determined using the following equation:

$$C_s = \frac{\sum_{n=1}^{N} (C_s Q_s)_n}{\sum_{n=1}^{N} (Q_s)_n}$$

where:

C_s = concentration of particulate matter in mg/dscm (gr/dscf) as determined by method 5.

N = total number of control devices tested.

Q_s = volumetric flow rate of the effluent gas stream in dscm/hr (dscf/hr) as determined by method 2.

$(C_s Q_s)_n$ or $(Q_s)_n$ = value of the applicable parameter for each control device tested.

(f) Any control device subject to the provisions of this subpart shall be designed and constructed to allow measurement of emissions using applicable test methods and procedures.

(g) Where emissions from any EAF(s) are combined with emissions from facilities not subject to the provisions of this subpart but controlled by a common capture system and control device, the owner or operator may use any of the following procedures during a performance test:

(1) Base compliance on control of the combined emissions.

(2) Utilize a method acceptable to the Administrator which compensates for the emissions from the facilities not subject to the provisions of this subpart.

(3) Any combination of the criteria of paragraphs (g)(1) and (g)(2) of this section.

(h) Where emissions from any EAF(s) are combined with emissions from facilities not subject to the provisions of this subpart, the owner or operator may use any of the following procedures for demonstrating compliance with § 60.272 (a)(3):

(1) Base compliance on control of the combined emissions.

(2) Shut down operation of facilities not subject to the provisions of this subpart.

(3) Any combination of the criteria of paragraphs (h)(1) and (h)(2) of this section.

* * * * *

(Secs. 111 and 114 of the Clean Air Act, as amended by sec. 4(a) of Pub. L. 91-604, 84 Stat. 1678 (42 U.S.C. 1857c-6, 1857c-9))

[FR Doc.75-25138 Filed 9-22-75;8:45 am]

17

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—A: PROGRAMS

[FRL 438-3]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority To State of California on Behalf of Kern County and Trinity County Air Pollution Control Districts

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of California on behalf of the Kern County Air Pollution Control District and the Trinity County Air Pollution Control District, dated August 18, 1975, EPA is today amending 40 CFR 60.4, Address, to reflect this delegation. A Notice announcing this delegation is published today at 40 FR ????. The amended § 60.4 is set forth below. It adds the addresses of the Kern County and Trinity County Air Pollution Control Districts, to which must be adressed all reports, requests, applications, submittals, and communications pursuant to this part by sources subject to the NSPS located within these Air Pollution Control Districts.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on August 18, 1975, and it serves no purpose to delay the technical change of this addition of the Air Pollution Control District addresses to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended. 42 U.S.C. 1857c-6.

Dated: September 25, 1975.

STANLEY W. LEGRO,
Assistant Administrator for Enforcement.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising paragraph F, to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)—(E) * * *

F—California—

Bay Area Air Pollution Control District, 939 Ellis St., San Francisco, CA 94109.

Del Norte County Air Pollution Control District, Courthouse, Crescent City, CA 95531.

Humboldt County Air Pollution Control District, 5600 S. Broadway, Eureka, CA 95501.

Kern County Air Pollution Control District, 1700 Flower St. (P.O. Box 997), Bakersfield, CA 93302.

Monterey Bay Unified Air Pollution Control District, 420 Church St. (P.O. Box 487), Salinas, CA 93901.

Trinity County Air Pollution Control District, Box AJ, Weaverville, CA 96093.

* * * * *

[FR Doc.75-26271 Filed 9-30-75;8:45 am]

18

[FRL 423-7]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Emission Monitoring Requirements and Revisions to Performance Testing Methods

On September 11, 1974 (39 FR 32852), the Environmental Protection Agency (EPA) proposed revisions to 40 CFR Part 60, Standards of Performance for New Stationary Sources, to establish specific requirements pertaining to continuous emission monitoring system performance specifications, operating procedures, data reduction, and reporting requirements.[23] These requirements would apply to new and modified facilities covered under Part 60, but would not apply to existing facilities.

Simultaneously (39 FR 32871), the Agency proposed revisions to 40 CFR Part 51, Requirements for the Preparation, Adoption, and Submittal of Implementation Plans, which would require States to revise their State Implementation Plans (SIP's) to include legal enforceable procedures requiring certain specified stationary sources to monitor emissions on a continuous basis. These requirements would apply to existing facilities, which are not covered under Part 60.

Interested parties participated in the rulemaking by sending comments to EPA. A total of 105 comment letters were received on the proposed revisions to Part 60 from monitoring equipment manufacturers, data processing equipment manufacturers, industrial users of monitoring equipment, air pollution control agencies including State, local, and EPA regional offices, other Federal agencies, and consultants. Copies of the comment letters received and a summary of the issues and EPA's responses are available for inspection and copying at the U.S. Environmental Protection Agency, Public Information Reference Unit, Room 2922 (EPA Library), 401 M Street, S.W., Washington, D.C. In addition, copies of the issue summary and EPA responses may be obtained upon written request from the EPA Public Information Center (PM-215), 401 M Street, S.W., Washington, D.C. 20460 (specify Public Comment Summary: Emission Monitoring Requirements). The comments have been carefully considered, additional information has been collected and assessed, and where determined by the Administrator to be appropriate, changes have been made to the proposed regulations. These changes are incorporated in the regulations promulgated herein.

Background

At the time the regulations were proposed (September 11, 1974), EPA had promulgated 12 standards of performance for new stationary sources under section 111 of the Clean Air Act, as amended, four of which required the affected facilities to install and operate systems which continuously monitor the levels of pollutant emissions, where the technical feasibility exists using currently available continuous monitoring technology, and where the cost of the systems is reasonable. When the four standards that require monitoring systems were promulgated, EPA had limited knowledge about the operation of such systems because only a few systems had been installed; thus, the requirements were specified in general terms. EPA initiated a program to develop performance specifications and obtain information on the operation of continuous monitoring systems. The program was designed to assess the systems' accuracy, reliability, costs, and problems related to installation, operation, maintenance, and data handling. The proposed regulations (39 FR 32852) were based on the results of this program.

The purpose of regulations promulgated herein is to establish minimum performance specifications for continuous monitoring systems, minimum data reduction requirements, operating procedures, and reporting requirements for those affected facilities required to install continuous monitoring systems. The specifications and procedures are designed to assure that the data obtained from continuous monitoring systems will be accurate and reliable and provide the necessary information for determining whether an owner or operator is following proper operation and maintenance procedures.

Significant Comments and Changes Made To Proposed Regulations

Many of the comment letters received by EPA contained multiple comments. The most significant comments and the differences between the proposed and final regulations are discussed below.

(1) Subpart A—General Provisions. The greatest number of comments received pertained to the methodology and expense of obtaining and reporting continuous monitoring system emission data. Both air pollution control agencies and affected users of monitoring equipment presented the view that the proposed regulations requiring that all emission data be reported were excessive, and that reports of only excess emissions and retention of all the data for two years on the affected facility's premises is sufficient. Twenty-five commentators suggested that the effectiveness of the operation and maintenance of an affected facility and its air pollution control system could be determined by reporting only excess emissions. Fifteen others recommended deleting the reporting requirements entirely.

EPA has reviewed these comments and has contacted vendors of monitoring and data acquisition equipment for additional information to more fully assess the impact of the proposed reporting requirements. Consideration was also given to the resources that would be required of EPA to enforce the proposed requirement, the costs that would be incurred by an affected source, and the effectiveness of the proposed requirement in comparison with a requirement to report only excess emissions. EPA concluded that reporting only excess emissions would assure proper operation and maintenance of the air pollution control equipment and would result in lower costs to the source and allow more effective use of EPA resources by eliminating the need for handling and storing large amounts of data. Therefore, the regulation promulgated herein requires owners or operators to report only excess emissions and to maintain a permanent record of all emission data for a period of two years.

In addition, the proposed specification of minimum data reduction procedures has been changed. Rather than requiring integrated averages as proposed, the regulations promulgated herein also specify a method by which a minimum number of data points may be used to compute average emission rates. For example, average opacity emissions over a six-minute period may be calculated from a minimum of 24 data points equally spaced over each six-minute period. Any number of equally spaced data points in excess of 24 or continuously integrated data may also be used to compute six-minute averages. This specification of minimum computation requirements combined with the requirement to report only excess emissions provides source owners and operators with maximum flexibility to select from a wide choice of optional data reduction procedures. Sources which monitor only opacity and which infrequently experience excess emissions may choose to utilize strip chart recorders, with or without continuous six-minute integrators; whereas sources monitoring two or more pollutants plus other parameters necessary to convert to units of the emission standard may choose to utilize existing computers or electronic data processes incorporated with the monitoring system. All data must be retained for two years, but only excess emissions need be reduced to units of the standard. However, in order to report excess emissions, adequate procedures must be utilized to insure that excess emissions are identified. Here again, certain sources with minimal excess emissions can determine excess emissions by review of strip charts, while sources with varying emission and excess air rates will most likely need to reduce all data to units of the standard to identify any excess emissions. The regulations promulgated herein allow the use of extractive, gaseous monitoring systems on a time sharing basis by installing sampling probes at several locations, provided the minimum number of data points (four per hour) are obtained.

Several commentators stated that the averaging periods for reduction of monitoring data, especially opacity, were too short and would result in an excessive amount of data that must be reduced and recorded. EPA evaluated these comments and concluded that to be useful to source owners and operators as well as enforcement agencies, the averaging time for the continuous monitoring data should be reasonably consistent with the averaging time for the reference methods used during performance tests. The data reduction requirements for opacity have been substantially reduced because the averaging period was changed from one

minute, which was proposed, to six minutes to be consistent with revisions made to Method 9 (39 FR 39872).

Numerous comments were received on proposed § 60.13 which resulted in several changes. The proposed section has been reorganized and revised in several respects to accommodate the comments and provide clarity, to more specifically delineate the equipment subject to Performance Specifications in Appendix B, and to more specifically define requirements for equipment purchased prior to September 11, 1974. The provisions in § 60.13 are not intended to prevent the use of any equipment that can be demonstrated to be reliable and accurate; therefore, the performance of monitoring systems is specified in general terms with minimal references to specific equipment types. The provisions in § 60.13(i) are included to allow owners or operators and equipment vendors to apply to the Administrator for approval to use alternative equipment or procedures when equipment capable of producing accurate results may not be commercially available (e.g. condensed water vapor interferes with measurement of opacity), when unusual circumstances may justify less costly procedures, or when the owner or operator or equipment vendor may simply prefer to use other equipment or procedures that are consistent with his current practices.

Several paragraphs in § 60.13 have been changed on the basis of the comments received. In response to comments that the monitor operating frequency requirements did not consider periods when the monitor is inoperative or undergoing maintenance, calibration, and adjustment, the operating frequency requirements have been changed. Also the frequency of cycling requirement for opacity monitors has been changed to be consistent with the response time requirement in Performance Specification 1, which reflects the capability of commercially available equipment.

A second area that received comment concerns maintenance performed upon continuous monitoring systems. Six commentators noted that the proposed regulation requiring extensive retesting of continuous monitoring systems for all minor failures would discourage proper maintenance of the systems. Two other commentators noted the difficulty of determining a general list of critical components, the replacement of which would automatically require a retest of the system. Nevertheless, it is EPA's opinion that some control must be exercised to insure that a suitable monitoring system is not rendered unsuitable by substantial alteration or a lack of needed maintenance. Accordingly, the regulations promulgated herein require that owners or operators submit with the quarterly report information on any repairs or modifications made to the system during the reporting period. Based upon this information, the Administrator may review the status of the monitoring system with the owner or operator and, if determined to be necessary, require retesting of the continuous monitoring system(s).

Several commentators noted that the proposed reporting requirements are unnecessary for affected facilities not required to install continuous monitoring systems. Consequently, the regulations promulgated herein do not contain the requirements.

Numerous comments were received which indicated that some monitoring systems may not be compatible with the proposed test procedures and requirements. The comments were evaluated and, where appropriate, the proposed test procedures and requirements were changed. The procedures and requirements promulgated herein are applicable to the majority of acceptable systems; however, EPA recognizes that there may be some acceptable systems available now or in the future which could not meet the requirements. Because of this, the regulations promulgated herein include a provision which allows the Administrator to approve alternative testing procedures. Eleven commentators noted that adjustment of the monitoring instruments may not be necessary as a result of daily zero and span checks. Accordingly, the regulations promulgated herein require adjustments only when applicable 24-hour drift limits are exceeded. Four commentators stated that it is not necessary to introduce calibration gases near the probe tips. EPA has demonstrated in field evaluations that this requirement is necessary in order to assure accurate results; therefore, the requirement has been retained. The requirement enables detection of any dilution or absorption of pollutant gas by the plumbing and conditioning systems prior to the pollutant gas entering the gas analyzer.

Provisions have been added to these regulations to require that the gas mixtures used for the daily calibration check of extractive continuous monitoring systems be traceable to National Bureau of Standards (NBS) reference gases. Calibration gases used to conduct system evaluations under Appendix B must either be analyzed prior to use or shown to be traceable to NBS materials. This traceability requirement will assure the accuracy of the calibration gas mixtures and the comparability of data from systems at all locations. These traceability requirements will not be applied whenever the NBS materials are not available. A list of available NBS Standard Reference Materials may be obtained from the Office of Standard Reference Materials, Room B311, Chemistry Building, National Bureau of Standards, Washington, D.C. 20234.

Recertification of the continued accuracy of the calibration gas mixtures is also necessary and should be performed at intervals recommended by the calibration gas mixture manufacturer. The NBS materials and calibration gas mixtures traceable to these materials should not be used after expiration of their stated shelf-life. Manufacturers of calibration gas mixtures generally use NBS materials for traceability purposes, therefore, these amendments to the regulations will not impose additional requirements upon most manufacturers.

(2) Subpart D—Fossil-Fuel Fired Steam Generators. Eighteen commentators had questions or remarks concerning the proposed revisions dealing with fuel analysis. The evaluation of these comments and discussions with coal suppliers and electric utility companies led the Agency to conclude that the proposed provisions for fuel analysis are not adequate or consistent with the current fuel situation. An attempt was made to revise the proposed provisions; however, it became apparent that an in-depth study would be necessary before meaningful provisions could be developed. The Agency has decided to promulgate all of the regulations except those dealing with fuel analysis. The fuel analysis provisions of Subpart D have been reserved in the regulations promulgated herein. The Agency has initiated a study to obtain the necessary information on the variability of sulfur content in fuels, and the capability of fossil fuel fired steam generators to use fuel analysis and blending to prevent excess sulfur dioxide emissions. The results of this study will be used to determine whether fuel analysis should be allowed as a means of measuring excess emissions, and if allowed, what procedure should be required. It should be pointed out that this action does not affect facilities which use flue gas desulfurization as a means of complying with the sulfur dioxide standard; these facilities are still required to install continuous emission monitoring systems for sulfur dioxide. Facilities which use low sulfur fuel as a means of complying with the sulfur dioxide standard may use a continuous sulfur dioxide monitor or fuel analysis. For facilities that elect to use fuel analysis procedures, fuels are not required to be sampled or analyzed for preparation of reports of excess emissions until the Agency finalizes the procedures and requirements.

Three commentators recommended that carbon dioxide continuous monitoring systems be allowed as an alternative for oxygen monitoring for measurement of the amount of diluents in flue gases from steam generators. The Agency agrees with this recommendation and has included a provision which allows the use of carbon dioxide monitors. This provision allows the use of pollutant monitors that produce data on a wet basis without requiring additional equipment or procedures for correction of data to a dry basis. Where CO_2 or O_2 data are not collected on a consistent basis (wet or dry) with the pollutant data, or where oxygen is measured on a wet basis, alternative procedures to provide corrections for stack moisture and excess air must be approved by the Administrator. Similarly, use of a carbon dioxide continuous monitoring system downstream of a flue gas desulfurization system is not permitted without the Administrator's prior approval due to the potential for absorption of CO_2 within the control device. It should be noted that when any fuel is fired directly in the stack gases

for reheating, the F and F_c factors promulgated herein must be prorated based upon the total heat input of the fuels fired within the facility regardless of the locations of fuel firing. Therefore, any facility using a flue gas desulfurization system may be limited to dry basis monitoring instrumentation due to the restrictions on use of a CO_2 diluent monitor unless water vapor is also measured subject to the Administrator's approval.

Two commentators requested that an additional factor (F_w) be developed for use with oxygen continuous monitoring systems that measure flue gas diluents on a wet basis. A factor of this type was evaluated by EPA, but is not being promulgated with the regulations herein. The error in the accuracy of the factor may exceed ±5 percent without additional measurements to correct for variations in flue gas moisture content due to fluctuations in ambient humidity or fuel moisture content. However, EPA will approve installation of wet basis oxygen systems on a case-by-case basis if the owner or operator will proposed use of additional measurements and procedures to control the accuracy of the F_w factor within acceptable limits. Applications for approval of such systems should include the frequency and type of additional measurements proposed and the resulting accuracy of the F_w factor under the extremes of operating conditions anticipated.

One commentator stated that the proposed requirements for recording heat input are superfluous because this information is not needed to convert monitoring data to units of the applicable standard. EPA has reevaluated this requirement and has determined that the conversion of excess emissions into units of the standards will be based upon the F factors and that measurement of the rates of fuel firing will not be needed except when combinations of fuels are fired. Accordingly, the regulations promulgated herein require such measurements only when multiple fuels are fired.

Thirteen commentators questioned the rationale for the proposed increased operating temperature of the Method 5 sampling train for fossil-fuel-fired steam generator particulate testing and the basis for raising rather than lowering the temperature. A brief discussion of the rationale behind this revision was provided in the preamble to the proposed regulations, and a more detailed discussion is provided here. Several factors are of primary importance in developing the data base for a standard of performance and in specifying the reference method for use in conducting a performance test, including:

a. The method used for data gathering to establish a standard must be the same as, or must have a known relationship to, the method subsequently established as the reference method.

b. The method should measure pollutant emissions indicative of the performance of the best systems of emission reduction. A method meeting this criterion will not necessarily measure emissions as they would exist after dilution and cooling to ambient temperature and pressure, as would occur upon release to the atmosphere. As such, an emission factor obtained through use of such a method would, for example, not necessarily be of use in an ambient dispersion model. This seeming inconsistency results from the fact that standards of performance are intended to result in installation of systems of emission reduction which are consistent with best demonstrated technology, considering cost. The Administrator, in establishing such standards, is required to identify best demonstrated technology and to develop standards which reflect such technology. In order for these standards to be meaningful, and for the required control technology to be predictable, the compliance methods must measure emissions which are indicative of the performance of such systems.

c. The method should include sufficient detail as needed to produce consistent and reliable test results.

EPA relies primarily upon Method 5 for gathering a consistent data base for particulate matter standards. Method 5 meets the above criteria by providing detailed sampling methodology and includes an out-of-stack filter to facilitate temperature control. The latter is needed to define particulate matter on a common basis since it is a function of temperature and is not an absolute quantity. If temperature is not controlled, and/or if the effect of temperature upon particulate formation is unknown, the effect on an emission control limitation for particulate matter may be variable and unpredictable.

Although selection of temperature can be varied from industry to industry, EPA specifies a nominal sampling temperature of 120° C for most source categories subject to standards of performance. Reasons for selection of 120° C include the following:

a. Filter temperature must be held above 100° C at sources where moist gas streams are present. Below 100° C, condensation can occur with resultant plugging of filters and possible gas/liquid reactions. A temperature of 120° C allows for expected temperature variation within the train, without dropping below 100° C.

b. Matter existing in particulate form at 120° C is indicative of the performance of the best particulate emission reduction systems for most industrial processes. These include systems of emission reduction that may involve not only the final control device, but also the process and stack gas conditioning systems.

c. Adherence to one established temperature (even though some variation may be needed for some source categories) allows comparison of emissions from source category to source category. This limited standardization used in the development of standards of performance is a benefit to equipment vendors and to source owners by providing a consistent basis for comparing test results and predicting control system performance. In comparison, in-stack filtration takes place at stack temperature, which usually is not constant from one source to the next. Since the temperature varies, in-stack filtration does not necessarily provide a consistent definition of particulate matter and does not allow for comparison of various systems of control. On these bases, Method 5 with a sampling filter temperature controlled at approximately 120° C was promulgated as the applicable test method for new fossil-fuel fired steam generators.

Subsequent to the promulgation of the standards of performance for steam generators, data became available indicating that certain combustion products which do not exist as particulate matter at the elevated temperatures existing in steam generator stacks may be collected by Method 5 at lower temperatures (below 160° C). Such material, existing in gaseous form at stack temperature, would not be controllable by emission reduction systems involving electrostatic precipitators (ESP). Consequently, measurement of such condensible matter would not be indicative of the control system performance. Studies conducted in the past two years have confirmed that such condensation can occur. At sources where fuels containing 0.3 to 0.85 percent sulfur were burned, the incremental increase in particulate matter concentration resulting from sampling at 120° C as compared to about 150° C was found to be variable, ranging from 0.001 to 0.008 gr/scf. The variability is not necessarily predictable, since total sulfur oxide concentration, boiler design and operation, and fuel additives each appear to have a potential effect. Based upon these data, it is concluded that the potential increase in particulate concentration at sources meeting the standard of performance for sulfur oxides is not a serious problem in comparison with the particulate standard which is approximately 0.07 gr/scf. Nevertheless, to insure that an unusual case will not occur where a high concentration of condensible matter, not controllable with an ESP, would prevent attainment of the particulate standard, the sampling temperature allowed at fossil-fuel fired steam boilers is being raised to 160° C. Since this temperature is attainable at new steam generator stacks, sampling at temperatures above 160° C would not yield results necessarily representative of the capabilities of the best systems of emission reduction.

In evaluating particulate sampling techniques and the effect of sampling temperature, particular attention has also been given to the possibility that SO_2 may react in the front half of the Method 5 train to form particulate matter. Based upon a series of comprehensive tests involving both source and controlled environments, EPA has developed data that show such reactions do not occur to a significant degree.

Several control agencies commented on the increase in sampling temperature and suggested that the need is for sampling at lower, not higher, temperatures. This is a relevant comment and is one which must be considered in terms of the basis upon which standards are established.

For existing boilers which are not subject to this standard, the existence of higher stack temperatures and/or the use of higher sulfur fuels may result in significant condensation and resultant high indicated particulate concentrations when sampling is conducted at 120° C. At one coal fired steam generator burning coal containing approximately three percent sulfur, EPA measurements at 120° C showed an increase of 0.05 gr/dscf over an average of seven runs compared to samples collected at approximately 150° C. It is believed that this increase resulted, in large part, if not totally, from SO_3 condensation which would occur also when the stack emissions are released into the atmosphere. Therefore, where standards are based upon emission reduction to achieve ambient air quality standards rather than on control technology (as is the case with the standards promulgated herein), a lower sampling temperature may be appropriate.

Seven commentators questioned the need for traversing for oxygen at 12 points within a duct during performance tests. This requirement, which is being revised to apply only when particulate sampling is performed (no more than 12 points are required) is included to insure that potential stratification resulting from air in-leakage will not adversely affect the accuracy of the particulate test.

Eight commentators stated that the requirement for continuous monitoring of nitrogen oxides should be deleted because only two air quality control regions have ambient levels of nitrogen dioxide that exceed the national ambient air quality standard for nitrogen dioxide. Standards of performance issued under section 111 of the Act are designed to require affected facilities to design and install the best systems of emission reduction (taking into account the cost of such reduction). Continuous emission monitoring systems are required to insure that the emission control systems are operated and maintained properly. Because of this, the Agency does not feel that it is appropriate to delete the continuous emission monitoring system requirements for nitrogen oxides; however, in evaluating these comments the Agency found that some situations may exist where the nitrogen oxides monitor is not necessary to insure proper operation and maintenance. The quantity of nitrogen oxides emitted from certain types of furnaces is considerably below the nitrogen oxides emission limitation. The low emission level is achieved through the design of the furnace and does not require specific operating procedures or maintenance on a continuous basis to keep the nitrogen oxides emissions below the applicable standard. Therefore, in this situation, a continuous emission monitoring system for nitrogen oxides is unnecessary. The regulations promulgated herein do not require continuous emission monitoring systems for nitrogen oxides on facilities whose emissions are 30 percent or more below the applicable standard.

Three commentators requested that owners or operators of steam generators be permitted to use NO_x continuous monitoring systems capable of measuring only nitric oxide (NO) since the amount of nitrogen dioxide (NO_2) in the flue gases is comparatively small. The regulations proposed and those promulgated herein allow use of such systems or any system meeting all of the requirements of Performance Specification 2 of Appendix B. A system that measures only nitric oxide (NO) may meet these specifications including the relative accuracy requirement (relative to the reference method tests which measure NO + NO_2) without modification. However, in the interests of maximizing the accuracy of the system and creating conditions favorable to acceptance of such systems (the cost of systems measuring only NO is less), the owner or operator may determine the proportion of NO_2 relative to NO in the flue gases and use a factor to adjust the continuous monitoring system emission data (e.g. 1.03 × NO = NO_x) provided that the factor is applied not only to the performance evaluation data, but also applied consistently to all data generated by the continuous monitoring system thereafter. This procedure is limited to facilities that have less than 10 percent NO_2 (greater than 90 percent NO) in order to not seriously impair the accuracy of the system due to NO_2 to NO proportion fluctuations.

Section 60.45(g)(1) has been reserved for the future specification of the excess emissions for opacity that must be reported. On November 12, 1974 (39 FR 39872), the Administrator promulgated revisions to Subpart A, General Provisions, pertaining to the opacity provisions and to Reference Method 9, Visual Determination of the Opacity of Emissions from Stationary Sources. On April 22, 1975 (40 FR 17778), the Agency issued a notice soliciting comments on the opacity provisions and Reference Method 9. The Agency intends to evaluate the comments received and make any appropriate revision to the opacity provisions and Reference Method 9. In addition, the Agency is evaluating the opacity standards for fossil-fuel fired steam generators under § 60.42(a)(2) to determine if changes are needed because of the new Reference Method 9. The provisions on excess emissions for opacity will be issued after the Agency completes its evaluation of the opacity standard.

(3) Subpart G—Nitric Acid Plants. Two commentators questioned the long-term validity of the proposed conversion procedures for reducing data to units of the standard. They suggested that the conversion could be accomplished by monitoring the flue gas volumetric rate. EPA reevaluated the proposed procedures and found that monitoring the flue gas volume would be the most direct method and would also be an accurate method of converting monitoring data, but would require the installation of an additional continuous monitoring system. Although this option is available and would be acceptable subject to the Administrator's approval, EPA does not believe that the additional expense this method (monitoring volumetric rate) would entail is warranted. Since nitric acid plants, for economic and technical reasons, typically operate within a fairly narrow range of conversion efficiencies (90–96 percent) and tail gas diluents (2–5 percent oxygen), the flue gas volumetric rates are reasonably proportional to the acid production rate. The error that would be introduced into the data from the maximum variation of these parameters is approximately 15 percent and would usually be much less. It is expected that the tail gas oxygen concentration (an indication of the degree of tail gas dilution) will be rigidly controlled at facilities using catalytic converter control equipment. Accordingly, the proposed procedures for data conversion have been retained due to the small benefit that would result from requiring additional monitoring equipment. Other procedures may be approved by the Administrator under § 60.13(i).

(4) Subpart H—Sulfuric Acid Plants. Two commentators stated that the proposed procedure for conversion of monitoring data to units of the standard would result in large data reduction errors. EPA has evaluated more closely the operations of sulfuric acid plants and agrees that the proposed procedure is inadequate. The proposed conversion procedure assumes that the operating conditions of the affected facility will remain approximately the same as during the continuous monitoring system evaluation tests. For sulfuric acid plants this assumption is invalid. A sulfuric acid plant is typically designed to operate at a constant volumetric throughput (scfm). Acid production rates are altered by by-passing portions of the process air around the furnace or combustor to vary the concentration of the gas entering the converter. This procedure produces widely varying amounts of tail gas dilution relative to the production rate. Accordingly, EPA has developed new conversion procedures whereby the appropriate conversion factor is computed from an analysis of the SO_2 concentration entering the converter. Air injection plants must make additional corrections for the diluent air added. Measurement of the inlet SO_2 is a normal quality control procedure used by most sulfuric acid plants and does not represent an additional cost burden. The Reich test or other suitable procedures may be used.

(5) Subpart J—Petroleum Refineries. One commentator stated that the requirements for installation of continuous monitoring systems for oxygen and firebox temperature are unnecessary and that installation of a flame detection device would be superior for process control purposes. Also, EPA has obtained data which show no identifiable relationship between furnace temperature, percent oxygen in the flue gas, and carbon monoxide emissions when the facility is operated in compliance with the applicable standard. Since firebox temperature and oxygen measurements may not be preferred by source owners and operators for process control, and no

known method is available for translation of these measurements into quantitative reports of excess carbon monoxide emissions, this requirement appears to be of little use to the affected facilities or to EPA. Accordingly, requirements for installation of continuous monitoring systems for measurements of firebox temperature and oxygen are deleted from the regulations.

Since EPA has not yet developed performance specifications for carbon monoxide or hydrogen sulfide continuous monitoring systems, the type of equipment that may be installed by an owner or operator in compliance with EPA requirements is undefined. Without conducting performance evaluations of such equipment, little reliance can be placed upon the value of any data such systems would generate. Therefore, the sections of the regulation requiring these systems are being reserved until EPA proposes performance specifications applicable to H_2S and CO monitoring systems. The provisions of § 60.105(a)(3) do not apply to an owner or operator electing to monitor H_2S. In that case, an H_2S monitor should not be installed until specific H_2S monitoring requirements are promulgated. At the time specifications are proposed, all owners or operators who have not entered into binding contractual obligations to purchase continuous monitoring equipment by **October 6, 1975** [23] will be required to install a carbon monoxide continuous monitoring system and a hydrogen sulfide continuous monitoring system (unless a sulfur dioxide continuous monitoring system has been installed) as applicable.

Section 60.105(a)(2), which specifies the excess emissions for opacity that must be reported, has been reserved for the same reasons discussed under fossil fuel-fired steam generators. [23]

(6) Appendix B—Performance Specifications. A large number of comments were received in reference to specific technical and editorial changes needed in the specifications. Each of these comments has been reviewed and several changes in format and procedures have been made. These include adding alignment procedures for opacity monitors and more specific instructions for selecting a location for installing the monitoring equipment. Span requirements have been specified so that commercially produced equipment may be standardized where possible. The format of the specifications was simplified by redefining the requirements in terms of percent opacity, or oxygen, or carbon dioxide, or percent of span. The proposed requirements were in terms of percent of the emission standard which is less convenient or too vague since reference to the emission standards would have represented a range of pollutant concentrations depending upon the amount of diluents (i.e. excess air and water vapor) that are present in the effluent. In order to calibrate gaseous monitors in terms of a specific concentration, the requirements were revised to delete reference to the emission standards.

Four commentators noted that the reference methods used to evaluate continuous monitoring system performance may be less accurate than the systems themselves. Five other commentators questioned the need for 27 nitrogen oxides reference method tests. The accuracy specification for gaseous monitoring systems was specified at 20 percent, a value in excess of the actual accuracy of monitoring systems that provides tolerance for reference method inaccuracy. Commercially available monitoring equipment has been evaluated using these procedures and the combined errors (i.e. relative accuracy) in the reference methods and the monitoring systems have been shown not to exceed 20 percent after the data are averaged by the specified procedures.

Twenty commentators noted that the cost estimates contained in the proposal did not fully reflect installation costs, data reduction and recording costs, and the costs of evaluating the continuous monitoring systems. As a result, EPA reevaluated the cost analysis. For opacity monitoring alone, investment costs including data reduction equipment and performance tests are approximately $20,000, and annual operating costs are approximately $8,500. The same location on the stack used for conducting performance tests with Reference Method 5 (particulate) may be used by installing a separate set of ports for the monitoring system so that no additional expense for access is required. For power plants that are required to install opacity, nitrogen oxides, sulfur dioxide, and diluent (O_2 or CO_2) monitoring systems, the investment cost is approximately $55,000, and the operating cost is approximately $30,000. These are significant costs but are not unreasonable in comparison to the approximately seven million dollar investment cost for the smallest steam generation facility affected by these regulations.

Effective date. These regulations are promulgated under the authority of sections 111, 114 and 301(a) of the Clean Air Act as amended [42 U.S.C. 1857c-6, 1857c-9, and 1857g(a)] and become effective October 6, 1975.

Dated: September 23, 1975.

JOHN QUARLES,
Acting Administrator

40 CFR Part 60 is amended by revising Subparts A, D, F, G, H, I, J, L, M, and O, and adding Appendix B as follows:

1. The table of sections is amended by revising Subpart A and adding Appendix B as follows:

Subpart A—General Provisions

* * * * *

60.13 Monitoring requirements.

* * * * *

APPENDIX B—PERFORMANCE SPECIFICATIONS

Performance Specification 1—Performance specifications and specification test procedures for transmissometer systems for continuous measurement of the opacity of stack emissions.

Performance Specification 2—Performance specifications and specification test procedures for monitors of SO_2 and NO_x from stationary sources.

Performance Specification 3—Performance specifications and specification test procedures for monitors of CO_2 and O_2 from stationary sources

* * * * *

Subpart A—General Provisions

Section 60.2 is amended by revising paragraph (r) and by adding paragraphs (x), (y), and (z) as follows:

§ 60.2 Definitions.

* * * * *

(r) "One-hour period" means any 60 minute period commencing on the hour.

* * * * *

(x) "Six-minute period" means any one of the 10 equal parts of a one-hour period.

(y) "Continuous monitoring system" means the total equipment, required under the emission monitoring sections in applicable subparts, used to sample and condition (if applicable), to analyze, and to provide a permanent record of emissions or process parameters.

(z) "Monitoring device" means the total equipment, required under the monitoring of operations sections in applicable subparts, used to measure and record (if applicable) process parameters.

3. In § 60.7, paragraph (a)(5) is added and paragraphs (b), (c), and (d) are revised. The added and revised provisions read as follows:

§ 60.7 Notification and record keeping.

(a) * * *

(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with § 60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) Each owner or operator required to install a continuous monitoring system shall submit a written report of excess emissions (as defined in applicable subparts) to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter and shall include the following information:

(1) The magnitude of excess emissions computed in accordance with § 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(d) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records.

4. A new § 60.13 is added as follows:

§ 60.13 Monitoring requirements.

(a) Unless otherwise approved by the Administrator or specified in applicable subparts, the requirements of this section shall apply to all continuous monitoring systems required under applicable subparts.

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under § 60.8. Verification of operational status shall, as a minimum, consist of the following:

(1) For continuous monitoring systems referenced in paragraph (c)(1) of this section, completion of the conditioning period specified by applicable requirements in Appendix B.

(2) For continuous monitoring systems referenced in paragraph (c)(2) of this section, completion of seven days of operation.

(3) For monitoring devices referenced in applicable subparts, completion of the manufacturer's written requirements or recommendations for checking the operation or calibration of the device.

(c) During any performance tests required under § 60.8 or within 30 days thereafter and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of any affected facility shall conduct continuous monitoring system performance evaluations and furnish the Administrator within 60 days thereof two or, upon request, more copies of a written report of the results of such tests. These continuous monitoring system performance evaluations shall be conducted in accordance with the following specifications and procedures:

(1) Continuous monitoring systems listed within this paragraph except as provided in paragraph (c)(2) of this section shall be evaluated in accordance with the requirements and procedures contained in the applicable performance specification of Appendix B as follows:

(i) Continuous monitoring systems for measuring opacity of emissions shall comply with Performance Specification 1.

(ii) Continuous monitoring systems for measuring nitrogen oxides emissions shall comply with Performance Specification 2.

(iii) Continuous monitoring systems for measuring sulfur dioxide emissions shall comply with Performance Specification 2.

(iv) Continuous monitoring systems for measuring the oxygen content or carbon dioxide content of effluent gases shall comply with Performance Specification 3.

(2) An owner or operator who, prior to September 11, 1974, entered into a binding contractual obligation to purchase specific continuous monitoring system components except as referenced by paragraph (c)(2)(iii) of this section shall comply with the following requirements:

(i) Continuous monitoring systems for measuring opacity of emissions shall be capable of measuring emission levels within ±20 percent with a confidence level of 95 percent. The Calibration Error Test and associated calculation procedures set forth in Performance Specification 1 of Appendix B shall be used for demonstrating compliance with this specification.

(ii) Continuous monitoring systems for measurement of nitrogen oxides or sulfur dioxide shall be capable of measuring emission levels within ±20 percent with a confidence level of 95 percent. The Calibration Error Test, the Field Test for Accuracy (Relative), and associated operating and calculation procedures set forth in Performance Specification 2 of Appendix B shall be used for demonstrating compliance with this specification.

(iii) Owners or operators of all continuous monitoring systems installed on an affected facility prior to [date of promulgation] are not required to conduct tests under paragraphs (c)(2)(i) and/or (ii) of this section unless requested by the Administrator.

(3) All continuous monitoring systems referenced by paragraph (c)(2) of this section shall be upgraded or replaced (if necessary) with new continuous monitoring systems, and such improved systems shall be demonstrated to comply with applicable performance specifications under paragraph (c)(1) of this section by September 11, 1979.

(d) Owners or operators of all continuous monitoring systems installed in accordance with the provisions of this part shall check the zero and span drift at least once daily in accordance with the method prescribed by the manufacturer of such systems unless the manufacturer recommends adjustments at shorter intervals, in which case such recommendations shall be followed. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour calibration drift limits of the applicable performance specifications in Appendix B are exceeded. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero or span drift adjustments except that for systems using automatic zero adjustments, the optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds four percent opacity. Unless otherwise approved by the Administrator, the following procedures, as applicable, shall be followed:

(1) For extractive continuous monitoring systems measuring gases, minimum procedures shall include introducing applicable zero and span gas mixtures into the measurement system as near the probe as is practical. Span and zero gases certified by their manufacturer to be traceable to National Bureau of Standards reference gases shall be used whenever these reference gases are available. The span and zero gas mixtures shall be the same composition as specified in Appendix B of this part. Every six months from date of manufacture, span and zero gases shall be reanalyzed by conducting triplicate analyses with Reference Methods 6 for SO_2, 7 for NO_x, and 3 for O_2 and CO_2, respectively. The gases may be analyzed at less frequent intervals if longer shelf lives are guaranteed by the manufacturer.

(2) For non-extractive continuous monitoring systems measuring gases, minimum procedures shall include upscale check(s) using a certified calibration gas cell or test cell which is functionally equivalent to a known gas concentration. The zero check may be performed by computing the zero value from upscale measurements or by mechanically producing a zero condition.

(3) For continuous monitoring systems measuring opacity of emissions, minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under paragraph (d) of this section, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by paragraphs (c)(1) and (2) of this section for measuring opacity of emissions shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 10-second period.

(2) All continuous monitoring systems referenced by paragraph (c)(1) of this section for measuring oxides of nitrogen, sulfur dioxide, carbon dioxide, or oxygen shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(3) All continuous monitoring systems referenced by paragraph (c)(2) of this section, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive one-hour period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of Appendix B of this part shall be used.

(g) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install applicable continuous monitoring systems on each separate effluent unless the installation of fewer systems is approved by the Administrator.

(h) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to six-minute averages and for systems other than opacity to one-hour averages for time periods under § 60.2 (x) and (r) respectively. Six-minute opacity averages shall be calculated from 24 or more data points equally spaced over each six-minute period. For systems other than opacity, one-hour averages shall be computed from four or more data points equally spaced over each one-hour period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data output of all continuous monitoring systems may be recorded in reduced or nonreduced form (e.g. ppm pollutant and percent O_2 or lb/million Btu of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in subparts to specify the applicable standard (e.g., rounded to the nearest one percent opacity).

(i) Upon written application by an owner or operator, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

(i) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances with the effluent gases.

(ii) Alternative monitoring requirements when the affected facility is infrequently operated.

(iii) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(iv) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(v) Alternative methods of converting pollutant concentration measurements to units of the standards.

(vi) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(vii) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

(viii) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, Appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.

(ix) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities are released to the atmosphere through more than one point.

Subpart D—Standards of Performance for Fossil Fuel-Fired Steam Generators

§ 60.42 [Amended]

5. Paragraph (a)(2) of § 60.42 is amended by deleting the second sentence.

6. Section 60.45 is amended by revising paragraphs (a), (b), (c), (d), (e), (f), and (g) as follows:

§ 60.45 Emission and fuel monitoring.

(a) A continuous monitoring system for measuring the opacity of emissions, except where gaseous fuel is the only fuel burned, shall be installed, calibrated, maintained, and operated by the owner or operator. The continuous monitoring system shall be spanned at 80 or 90 or 100 percent opacity.

(b) A continuous monitoring system for measuring sulfur dioxide emissions, shall be installed, calibrated, maintained and operated by the owner or operator except where gaseous fuel is the only fuel burned or where low sulfur fuels are used to achieve compliance with the standard under § 60.43 and fuel analyses under paragraph (b)(2) of this section are conducted. The following procedures shall be used for monitoring sulfur dioxide emissions:

(1) For affected facilities which use continuous monitoring systems, Reference Method 6 shall be used for conducting monitoring system performance evaluations under § 60.13(c). The pollutant gas used to prepare calibration gas mixtures under paragraph 2.1, Performance Specification 2 and for calibration checks under § 60.13(d) to this part, shall be sulfur dioxide (SO_2). The span value for the continuous monitoring system shall be determined as follows:

(i) For affected facilities firing liquid fossil fuel the span value shall be 1000 ppm sulfur dioxide.

(ii) For affected facilities firing solid fossil fuel the span value shall be 1500 ppm sulfur dioxide.

(iii) For affected facilities firing fossil fuels in any combination, the span value shall be determined by computation in accordance with the following formula and rounding to the nearest 500 ppm sulfur dioxide:

$$1000y+1500z$$

where:

y = the fraction of total heat input derived from liquid fossil fuel, and

z = the fraction of total heat input derived from solid fossil fuel.

(iv) For affected facilities which fire both fossil fuels and nonfossil fuels, the span value shall be subject to the Administrator's approval.

(2) [Reserved]

(3) For affected facilities using flue gas desulfurization systems to achieve compliance with sulfur dioxide standards under § 60.43, the continuous monitoring system for measuring sulfur dioxide emissions shall be located downstream of the desulfurization system and in accordance with requirements in Performance Specification 2 of Appendix B and the following:

(i) Owners or operators shall install CO_2 continuous monitoring systems, if selected under paragraph (d) of this section, at a location upstream of the desulfurization system. This option may be used only if the owner or operator can demonstrate that air is not added to the flue gas between the CO_2 continuous monitoring system and the SO_2 continuous monitoring system and each system measures the CO_2 and SO_2 on a dry basis.

(ii) Owners or operators who install O_2 continuous monitoring systems under paragraph (d) of this section shall select a location downstream of the desulfurization system and all measurements shall be made on a dry basis.

(iii) If fuel of a different type than is used in the boiler is fired directly into the flue gas for any purpose (e.g., reheating) the F or Fc factors used shall be prorated under paragraph (f)(6) of this section with consideration given to the fraction of total heat input supplied by the additional fuel. The pollutant, opacity, CO_2, or O_2 continuous monitoring system(s) shall be installed downstream of any location at which fuel is fired directly into the flue gas.

(c) A continuous monitoring system for the measurement of nitrogen oxides emissions shall be installed, calibrated, maintained, and operated by the owner

or operator except for any affected facility demonstrated during performance tests under § 60.8 to emit nitrogen oxides pollutants at levels 30 percent or more below applicable standards under § 60.44 of this part. The following procedures shall be used for determining the span and for calibrating nitrogen oxides continuous monitoring systems:

(1) The span value shall be determined as follows:

(i) For affected facilities firing gaseous fossil fuel the span value shall be 500 ppm nitrogen oxides.

(ii) For affected facilities firing liquid fossil fuel the span value shall be 500 ppm nitrogen oxides.

(iii) For affected facilities firing solid fossil fuel the span value shall be 1000 ppm nitrogen oxides.

(iv) For affected facilities firing fossil fuels in any combination, the span value shall be determined by computation in accordance with the following formula and rounding to the nearest 500 ppm nitrogen oxides:

$$500\,(x+y)+1000z$$

where:

x = the fraction of total heat input derived from gaseous fossil fuel,

y = the fraction of total heat input derived from liquid fossil fuel, and

z = the fraction of total heat input derived from solid fossil fuel.

(v) For affected facilities which fire both fossil fuels and nonfossil fuels, the span value shall be subject to the Administrator's approval.

(2) The pollutant gas used to prepare calibration gas mixtures under paragraph 2.1, Performance Specification 2 and for calibration checks under § 60.13 (d) to this part, shall be nitric oxide (NO). Reference Method 7 shall be used for conducting monitoring system performance evaluations under § 60.13(c).

(d) A continuous monitoring system for measuring either oxygen or carbon dioxide in the flue gases shall be installed, calibrated, maintained, and operated by the owner or operator.

(e) An owner or operator required to install continuous monitoring systems under paragraphs (b) and (c) of this section shall for each pollutant monitored use the applicable conversion procedure for the purpose of converting continuous monitoring data into units of the applicable standards (g/million cal, lb/million Btu) as follows:

(1) When the owner or operator elects under paragraph (d) of this section to measure oxygen in the flue gases, the measurement of the pollutant concentration and oxygen concentration shall each be on a dry basis and the following conversion procedure shall be used:

$$E=CF\left(\frac{20.9}{20.9-\%O_2}\right)$$

where:

E, C, F and $\%O_2$ are determined under paragraph (f) of this section.

(2) When the owner or operator elects under paragraph (d) of this section to measure carbon dioxide in the flue gases, the measurement of the pollutant concentration and the carbon dioxide concentration shall be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E=CF_c\left[\frac{100}{\%\,CO_2}\right]$$

where:

E, C, F_c, and $\%CO_2$ are determined under paragraph (f) of this section.

(f) The values used in the equations under paragraphs (e) (1) and (2) of this section are derived as follows:

(1) E = pollutant emission, g/million cal (lb/million Btu).

(2) C = pollutant concentration, g/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour priod by 4.15×10^{-5} M g/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for sulfur dioxide and 46.01 for nitrogen oxides.

(3) $\%O_2$, $\%CO_2$= oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under paragraph (d) of this section.

(4) F, F_c= a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

$$F=\left[\frac{227.0\%H+95.7\%C+35.4\%S+8.6\%N-28.5\%O}{GCV}\right]\text{ (metric units)}$$

$$F=\frac{10^6\,[6.34\%H+1.53\%C+0.57\%S+0.14\%N-0.46\%O]}{GCV}\text{ (English units)}$$

$$F_c=\frac{20.0\%C}{GCV}\text{ (metric units)}$$

$$F_c=\frac{321\times10^3\%C}{GCV}\text{ (English units)}$$

(i) H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using A.S.T.M. method D3178–74 or D3176 (solid fuels), or computed from results using A.S.T.M. methods D1137–53(70), D1945–64(73), or D1946–67(72) (gaseous fuels) as applicable.

(ii) GCV is the gross calorific value (cal/g, Btu/lb) of the fuel combusted, determined by the A.S.T.M. test methods D2015–66(72) for solid fuels and D1826–64(70) for gaseous fuels as applicable.

(6) For affected facilities firing combinations of fossil fuels, the F or F_c factors determined by paragraphs (f) (4) or (5) of this section shall be prorated in accordance with the applicable formula as follows:

(i) $F=xF_1+yF_2+zF_3$

where:

x, y, z = the fraction of total heat input derived from gaseous, liquid, and solid fuel respectively.

F_1, F_2, F_3 = the value of F for gaseous, liquid, and solid fossil fuels respectively under paragraphs (f) (4) or (5) of this section.

(i) For anthracite coal as classified according to A.S.T.M. D388–66, F=1.139 dscm/million cal (10140 dscf/million Btu) and F_c=0.222 scm CO_2/million cal (1980 scf CO_2/million Btu).

(ii) For sub-bituminous and bituminous coal as classified according to ASTM D388–66, F=1.103 dscm/million cal (9820 dscf/million Btu) and F_c=0.203 scm CO_2/million cal (1810 scf CO_2/million Btu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F=1 036 dscm/million cal (9220 dscf/million Btu) and F_c=0.161 scm CO_2/million cal (1430 scf CO_2/million Btu).

(iv) For gaseous fossil fuels, F=0.982 dscm/million cal (8740 dscf/million Btu). For natural gas, propane, and butane fuels, F_c=0.117 scm CO_2/million cal (1040 scf CO_2/million Btu) for natural gas, 0.135 scm CO_2/million cal (1200 scf CO_2/million Btu) for propane, and 0.142 scm CO_2/million cal (1260 scf CO_2/million Btu) for butane.

(5) The owner or operator may use the following equation to determine an F factor (dscm/million cal, or dscf/million Btu) on a dry basis (if it is desired to calculate F on a wet basis, consult with the Administrator) or F_c factor (scm CO_2/ million cal, or scf CO_2/million Btu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:

(ii) $$F_c=\sum_{i=1}^{n}X_i(F_c)_i$$

where:

x_i = the fraction of total heat input derived from each type fuel (e.g., natural gas, butane, crude, bituminous coal, etc.).

$(F_c)_i$ = the applicable F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (5) of this section.

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or F_c value shall be subject to the Administrator's approval.

(g) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) [Reserved]

(2) Sulfur dioxide. Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under § 60.43.

(ii) [Reserved]

(3) Nitrogen oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitro-

gen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under § 60.44.

7. Section 60.46 is revised to read as follows:

§ 60.46 Test methods and procedures.

(a) The reference methods in Appendix A of this part, except as provided in § 60.8(b), shall be used to determine compliance with the standards as prescribed in §§ 60.42, 60.43, and 60.44 as follows:

(1) Method 1 for selection of sampling site and sample traverses.

(2) Method 3 for gas analysis to be used when applying Reference Methods 5, 6 and 7.

(3) Method 5 for concentration of particulate matter and the associated moisture content.

(4) Method 6 for concentration of SO_2, and

(5) Method 7 for concentration of NOx.

(b) For Method 5, Method 1 shall be used to select the sampling site and the number of traverse sampling points. The sampling time for each run shall be at least 60 minutes and the minimum sampling volume shall be 0.85 dscm (30 dscf) except that smaller sampling times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator. The probe and filter holder heating systems in the sampling train shall be set to provide a gas temperature no greater than 160° C (320° F).

(c) For Methods 6 and 7, the sampling site shall be the same as that selected for Method 5. The sampling point in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). For Method 6, the sample shall be extracted at a rate proportional to the gas velocity at the sampling point.

(d) For Method 6, the minimum sampling time shall be 20 minutes and the minimum sampling volume 0.02 dscm (0.71 dscf) for each sample. The arithmetic mean of two samples shall constitute one run. Samples shall be taken at approximately 30-minute intervals.

(e) For Method 7, each run shall consist of at least four grab-samples taken at approximately 15-minute intervals. The arithmetic mean of the samples shall constitute the run value.

(f) For each run using the methods specified by paragraphs (a) (3), (4), and (5) of this section, the emissions expressed in g/million cal (lb/million Btu) shall be determined by the following procedure:

$$E = CF\left(\frac{20.9}{20.9 - \%O_2}\right)$$

where:

(1) E = pollutant emission g/million cal (lb/million Btu)

(2) C = pollutant concentration, g/dscm (lb/dscf), determined by Methods 5, 6, or 7

(3) $\%O_2$ = oxygen content by volume (expressed as percent), dry basis. Percent oxygen shall be determined by using the integrated or grab sampling and analysis procedures of Method 3 as applicable. The sample shall be obtained as follows:

(i) For determination of sulfur dioxide and nitrogen oxides emissions, the oxygen sample shall be obtained simultaneously at the same point in the duct as used to obtain the samples for Methods 6 and 7 determinations, respectively [§ 60.46(c)]. For Method 7, the oxygen sample shall be obtained using the grab sampling and analysis procedures of Method 3.

(ii) For determination of particulate emissions, the oxygen sample shall be obtained simultaneously by traversing the duct at the same sampling location used for each run of Method 5 under paragraph (b) of this section. Method 1 shall be used for selection of the number of traverse points except that no more than 12 sample points are required.

(4) F = a factor as determined in paragraphs (f) (4), (5) or (6) of § 60.45.

(g) When combinations of fossil fuels are fired, the heat input, expressed in cal/hr (Btu/hr), shall be determined during each testing period by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned. Gross calorific value shall be determined in accordance with A.S.T.M. methods D2015–66(72) (solid fuels), D240–64(73) (liquid fuels), or D1826–64(70) (gaseous fuels) as applicable. The rate of fuels burned during each testing period shall be determined by suitable methods and shall be confirmed by a material balance over the steam generation system.

Subpart F—Standards of Performance for Portland Cement Plants

§ 60.62 [Amended]

8. Section 60.62 is amended by deleting paragraph (d).

Subpart G—Standards of Performance for Nitric Acid Plants

§ 60.72 [Amended]

9. Paragraph (a)(2) of § 60.72 is amended by deleting the second sentence.

10. Section 60.73 is amended by revising paragraphs (a), (b), (c), and (e) to read as follows:

§ 60.73 Emission monitoring.

(a) A continuous monitoring system for the measurement of nitrogen oxides shall be installed, calibrated, maintained, and operated by the owner or operator. The pollutant gas used to prepare calibration gas mixtures under paragraph 2.1, Performance Specification 2 and for calibration checks under § 60.13(d) to this part, shall be nitrogen dioxide (NO_2). The span shall be set at 500 ppm of nitrogen dioxide. Reference Method 7 shall be used for conducting monitoring system performance evaluations under § 60.13(c).

(b) The owner or operator shall establish a conversion factor for the purpose of converting monitoring data into units of the applicable standard (kg/metric ton, lb/short ton). The conversion factor shall be established by measuring emissions with the continuous monitoring system concurrent with measuring emissions with the applicable reference method tests. Using only that portion of the continuous monitoring emission data that represents emission measurements concurrent with the reference method test periods, the conversion factor shall be determined by dividing the reference method test data averages by the monitoring data averages to obtain a ratio expressed in units of the applicable standard to units of the monitoring data, i.e., kg/metric ton per ppm (lb/short ton per ppm). The conversion factor shall be reestablished during any performance test under § 60.8 or any continuous monitoring system performance evaluation under § 60.13(c).

(c) The owner or operator shall record the daily production rate and hours of operation.

* * * * *

(e) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as any three-hour period during which the average nitrogen oxides emissions (arithmetic average of three contiguous one-hour periods) as measured by a continuous monitoring system exceed the standard under § 60.72(a).

Subpart H—Standards of Performance for Sulfuric Acid Plants

§ 60.83 [Amended]

11. Paragraph (a)(2) of § 60.83 is amended by deleting the second sentence.

12. Section 60.84 is amended by revising paragraphs (a), (b), (c), and (e) to read as follows:

§ 60.84 Emission monitoring.

(a) A continuous monitoring system for the measurement of sulfur dioxide shall be installed, calibrated, maintained, and operated by the owner or operator. The pollutant gas used to prepare calibration gas mixtures under paragraph 2.1, Performance Specification 2 and for calibration checks under § 60.13(d) to this part, shall be sulfur dioxide (SO_2). Reference Method 8 shall be used for conducting monitoring system performance evaluations under § 60.13(c) except that only the sulfur dioxide portion of the Method 8 results shall be used. The span shall be set at 1000 ppm of sulfur dioxide.

(b) The owner or operator shall establish a conversion factor for the purpose of converting monitoring data into units of the applicable standard (kg/metric ton, lb/short ton). The conversion factor shall be determined, as a minimum, three times daily by measuring the concentration of sulfur dioxide entering the converter using suitable methods (e.g., the Reich test, National Air Pollution Control Administration Publication No. 999–AP–13 and calculating the appropriate conversion factor for each eight-hour period as follows:

$$CF = k\left[\frac{1.000 - 0.015r}{r - s}\right]$$

where:

CF = conversion factor (kg/metric ton per ppm, lb/short ton per ppm).
k = constant derived from material balance. For determining CF in metric units, k = 0.0653. For determining CF in English units, k = 0.1306.
r = percentage of sulfur dioxide by volume entering the gas converter. Appropriate corrections must be made for air injection plants subject to the Administrator's approval.
s = percentage of sulfur dioxide by volume in the emissions to the atmosphere determined by the continuous monitoring system required under paragraph (a) of this section.

(c) The owner or operator shall record all conversion factors and values under paragraph (b) of this section from which they were computed (i.e., CF, r, and s)

* * * * *

(e) For the purpose of reports under § 60.7(c), periods of excess emissions shall be all three-hour periods (or the arithmetic average of three consecutive one-hour periods) during which the integrated average sulfur dioxide emissions exceed the applicable standards under § 60.82.

Subpart I—Standards of Performance for Asphalt Concrete Plants

§ 60.92 [Amended]

13. Paragraph (a)(2) of § 60.92 is amended by deleting the second sentence.

Subpart J—Standards of Performance for Petroleum Refineries

§ 60.102 [Amended]

14. Paragraph (a)(2) of § 60.102 is amended by deleting the second sentence.

15. Section 60.105 is amended by revising paragraphs (a), (b), and (e) to read as follows:

§ 60.105 **Emission monitoring.**

(a) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator as follows:

(1) A continuous monitoring system for the measurement of the opacity of emissions discharged into the atmosphere from the fluid catalytic cracking unit catalyst regenerator. The continuous monitoring system shall be spanned at 60, 70, or 80 percent opacity.

(2) [Reserved]

(3) A continuous monitoring system for the measurement of sulfur dioxide in the gases discharged into the atmosphere from the combustion of fuel gases (except where a continuous monitoring system for the measurement of hydrogen sulfide is installed under paragraph (a)(4) of this section). The pollutant gas used to prepare calibration gas mixtures under paragraph 2.1, Performance Specification 2 and for calibration checks under § 60.13(d) to this part, shall be sulfur dioxide (SO_2). The span shall be set at 100 ppm. For conducting monitoring system performance evaluations under § 60.13(c), Reference Method 6 shall be used.

(4) [Reserved]

(b) [Reserved]

* * * * *

(e) For the purpose of reports under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) [Reserved]

(2) [Reserved]

(3) [Reserved]

(4) Any six-hour period during which the average emissions (arithmetic average of six contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the standard under § 60.104.

Subpart L—Standards of Performance for Secondary Lead Smelters

§ 60.122 [Amended]

16. Section 60.122 is amended by deleting paragraph (c).

* * * * *

Subpart M—Standards of Performance for Secondary Brass and Bronze Ingot Production Plants

§ 60.132 [Amended]

17. Section 60.132 is amended by deleting paragraph (c).

* * * * *

Subpart O—Standards of Performance for Sewage Treatment Plants

§ 60.152 [Amended]

18. Paragraph (a)(2) of § 60.152 is amended by deleting the second sentence.

* * * * *

19. Part 60 is amended by adding Appendix B as follows:

APPENDIX B—PERFORMANCE SPECIFICATIONS

Performance Specification 1—Performance specifications and specification test procedures for transmissometer systems for continuous monitoring system exceed the emissions.

1 Principle and Applicability.

1.1 Principle The opacity of particulate matter in stack emissions is measured by a continuously operating emission measurement system. These systems are based upon the principle of transmissometry which is a direct measurement of the attenuation of visible radiation (opacity) by particulate matter in a stack effluent. Light having specific spectral characteristics is projected from a lamp across the stack of a pollutant source to a light sensor. The light is attenuated due to absorption and scatter by the particulate matter in the effluent The percentage of visible light attenuated is defined as the opacity of the emission. Transparent stack emissions that do not attenuate light will have a transmittance of 100 or an opacity of 0. Opaque stack emissions that attenuate all of the visible light will have a transmittance of 0 or an opacity of 100 percent. The transmissometer is evaluated by use of neutral density filters to determine the precision of the continuous monitoring system. Tests of the system are performed to determine zero drift, calibration drift, and response time characteristics of the system.

1.2 Applicability. This performance specification is applicable to the continuous monitoring systems specified in the subparts for measuring opacity of emissions. Specifications for continuous measurement of visible emissions are given in terms of design, performance, and installation parameters. These specifications contain test procedures, instalistion requirements, and data computation procedures for evaluating the acceptability of the continuous monitoring systems subject to approval by the Administrator.

2. Apparatus.

2.1 Calibrated Filters. Optical filters with neutral spectral characteristics and known optical densities to visible light or screens known to produce specified optical densities Calibrated filters with accuracies certified by the manufacturer to within ±3 percent opacity shall be used. Filters required are low, mid, and high-range filters with nominal optical densities as follows when the transmissometer is spanned at opacity levels specified by applicable subparts:

Span value (percent opacity)	Calibrated filter optical densities with equivalent opacity in parenthesis		
	Low-range	Mid-range	High-range
50	0.1 (20)	0.2 (37)	0.3 (50)
60	.1 (20)	.2 (37)	.3 (50)
70	.1 (20)	.3 (50)	.4 (60)
80	.1 (20)	.3 (50)	.6 (75)
90	.1 (20)	.4 (60)	.7 (80)
100	.1 (20)	.4 (60)	.9 (87½)

It is recommended that filter calibrations be checked with a well-collimated photopic transmissometer of known linearity prior to use. The filters shall be of sufficient size to attenuate the entire light beam of the transmissometer.

2.2 Data Recorder. Analog chart recorder or other suitable device with input voltage range compatible with the analyzer system output. The resolution of the recorder's data output shall be sufficient to allow completion of the test procedures within this specification.

2.3 Opacity measurement System. An in-stack transmissometer (folded or single path) with the optical design specifications designated below, associated control units and apparatus to keep optical surfaces clean.

3. Definitions.

3.1 Continuous Monitoring System. The total equipment required for the determination of pollutant opacity in a source effluent. Continuous monitoring systems consist of major subsystems as follows:

3.1.1 Sampling Interface. The portion of a continuous monitoring system for opacity that protects the analyzer from the effluent

3.1.2 Analyzer. That portion of the continuous monitoring system which senses the pollutant and generates a signal output that is a function of the pollutant opacity.

3.1.3 Data Recorder. That portion of the continuous monitoring system that processes the analyzer output and provides a permanent record of the output signal in terms of pollutant opacity.

3.2 Transmissometer. The portions of a continuous monitoring system for opacity that include the sampling interface and the analyzer.

3.3 Span. The value of opacity at which the continuous monitoring system is set to produce the maximum data display output. The span shall be set at an opacity specified in each applicable subpart.

3.4 Calibration Error. The difference between the opacity reading indicated by the continuous monitoring system and the known values of a series of test standards For this method the test standards are a series of calibrated optical filters or screens.

3.5 Zero Drift. The change in continuous monitoring system output over a stated period of time of normal continuous operation

when the pollutant concentration at the time of the measurements is zero.

3.6 Calibration Drift. The change in the continuous monitoring system output over a stated period of time of normal continuous operation when the pollutant concentration at the time of the measurements is the same known upscale value.

3.7 System Response. The time interval from a step change in opacity in the stack at the input to the continuous monitoring system to the time at which 95 percent of the corresponding final value is reached as displayed on the continuous monitoring system data recorder.

3.8 Operational Test Period. A minimum period of time over which a continuous monitoring system is expected to operate within certain performance specifications without unscheduled maintenance, repair, or adjustment.

3.9 Transmittance. The fraction of incident light that is transmitted through an optical medium of interest.

3.10 Opacity. The fraction of incident light that is attenuated by an optical medium of interest. Opacity (O) and transmittance (T) are related as follows:

$$O=1-T$$

3.11 Optical Density. A logarithmic measure of the amount of light that it attenuated by an optical medium of interest. Optical density (D) is related to the transmittance and opacity as follows:

$D=-\log_{10}T$

$D=-\log_{10}(1-O)$

3.12 Peak Optical Response. The wavelength of maximum sensitivity of the instrument.

3.13 Mean Spectral Response. The wavelength which bisects the total area under the curve obtained pursuant to paragraph 9.2.1.

3.14 Angle of View. The maximum (total) angle of radiation detection by the photodetector assembly of the analyzer.

3.15 Angle of Projection. The maximum (total) angle that contains 95 percent of the radiation projected from the lamp assembly of the analyzer.

3.16 Pathlength. The depth of effluent in the light beam between the receiver and the transmitter of the single-pass transmissometer, or the depth of effluent between the transceiver and reflector of a double-pass transmissometer. Two pathlengths are referenced by this specification:

3.16.1 Monitor Pathlength. The depth of effluent at the installed location of the continuous monitoring system.

3.16.2 Emission Outlet Pathlength. The depth of effluent at the location emissions are released to the atmosphere

4. Installation Specification.

4.1 *Location* The transmissometer must be located across a section of duct or stack that will provide a particulate matter flow through the optical volume of the transmissometer that is representative of the particulate matter flow through the duct or stack It is recommended that the monitor pathlength or depth of effluent for the transmissometer include the entire diameter of the duct or stack. In installations using a shorter pathlength, extra caution must be used in determining the measurement location representative of the particulate matter flow through the duct or stack.

4.1.1 The transmissometer location shall be downstream from all particulate control equipment.

4.1.2 The transmissometer shall be located as far from bends and obstructions as practical.

4.1.3 A transmissometer that is located in the duct or stack following a bend shall be installed in the plane defined by the bend where possible.

4.1.4 The transmissometer should be installed in an accessible location.

4.1.5 When required by the Administrator, the owner or operator of a source must demonstrate that the transmissometer is located in a section of duct or stack where a representative particulate matter distribution exists. The determination shall be accomplished by examining the opacity profile of the effluent at a series of positions across the duct or stack while the plant is in operation at maximum or reduced operating rates or by other tests acceptable to the Administrator.

4.2 *Slotted Tube. Installations* that require the use of a slotted tube shall use a slotted tube of sufficient size and blackness so as not to interfere with the free flow of effluent through the entire optical volume of the transmissometer or reflect light into the transmissometer photodetector. Light reflections may be prevented by using blackened baffles within the slotted tube to prevent the lamp radiation from impinging upon the tube walls, by restricting the angle of projection of the light and the angle of view of the photodetector assembly to less than the cross-sectional area of the slotted tube, or by other methods. The owner or operator must show that the manufacturer of the monitoring system has used appropriate methods to minimize light reflections for systems using slotted tubes.

4.3 Data Recorder Output. The continuous monitoring system output shall permit expanded display of the span opacity on a standard 0 to 100 percent scale Since all opacity standards are based on the opacity of the effluent exhausted to the atmosphere, the system output shall be based upon the emission outlet pathlength and permanently recorded. For affected facilities whose monitor pathlength is different from the facility's emission outlet pathlength, a graph shall be provided with the installation to show the relationships between the continuous monitoring system recorded opacity based upon the emission outlet pathlength and the opacity of the effluent at the analyzer location (monitor pathlength) Tests for measurement of opacity that are required by this performance specification are based upon the monitor pathlength. The graph necessary to convert the data recorder output to the monitor pathlength basis shall be established as follows:

$$\log(1-O_2)=(l_1/l_2\log(1-O_1)$$

where:

O_1 = the opacity of the effluent based upon l_1.

O_2 = the opacity of the effluent based upon l_2.

l_1 = the emission outlet pathlength.

l_2 = the monitor pathlength.

5. Optical Design Specifications.

The optical design specifications set forth in Section 6.1 shall be met in order for a measurement system to comply with the requirements of this method

6. Determination of Conformance with Design Specifications

6.1 The continuous monitoring system for measurement of opacity shall be demonstrated to conform to the design specifications set forth as follows:

6.1.1 Peak Spectral Response. The peak spectral response of the continuous monitoring systems shall occur between 500 nm and 600 nm. Response at any wavelength below 400 nm or above 700 nm shall be less than 10 percent of the peak response of the continuous monitoring system.

6.1.2 Mean Spectral Response. The mean spectral response of the continuous monitoring system shall occur between 500 nm and 600 nm.

6.1.3 Angle of View. The total angle of view shall be no greater than 5 degrees.

6.1.4 Angle of Projection. The total angle of projection shall be no greater than 5 degress.

6.2 Conformance with requirements under Section 6.1 of this specification may be demonstrated by the owner or operator of the affected facility or by the manufacturer of the opacity measurement system. Where conformance is demonstrated by the manufacturer, certification that the tests were performed, a description of the test procedures, and the test results shall be provided by the manufacturer. If the source owner or operator demonstrates conformance, the procedures used and results obtained shall be reported.

6.3 The general test procedures to be followed to demonstrate conformance with Section 6 requirements are given as follows: (These procedures will not be applicable to all designs and will require modification in some cases. Where analyzer and optical design is certified by the manufacturer to conform with the angle of view or angle of projection specifications, the respective procedures may be omitted.)

6.3.1 Spectral Response. Obtain spectral data for detector, lamp, and filter components used in the measurement system from their respective manufacturers.

6.3.2 Angle of View. Set the received up as specified by the manufacturer. Draw an arc with radius of 3 meters. Measure the receiver response to a small (less than 3 centimeters) non-directional light source at 5-centimeter intervals on the arc for 26 centimeters on either side of the detector centerline. Repeat the test in the vertical direction.

6.3.3 Angle of Projection. Set the projector up as specified by the manufacturer. Draw an arc with radius of 3 meters. Using a small photoelectric light detector (less than 3 centimeters), measure the light intensity at 5-centimeter intervals on the arc for 26 centimeters on either side of the light source centerline of projection. Repeat the test in the vertical direction.

7. Continuous Monitoring System Performance Specifications.

The continuous monitoring system shall meet the performance specifications in Table 1-1 to be considered acceptable under this method.

TABLE 1-1 —*Performance specifications*

Parameter	*Specifications*
a. Calibration error	≤3 pct opacity.[1]
b Zero drift (24 h)	≤2 pct opacity.[1]
c. Calibration drift (24 h)	≤2 pct opacity.[1]
d Response time	10 s (maximum).
e. Operational test period	168 h.

[1] Expressed as sum of absolute mean value and the 95 pct confidence interval of a series of tests.

8. Performance Specification Test Procedures. The following test procedures shall be used to determine conformance with the requirements of paragraph 7:

8.1 Calibration Error and Response Time Test. These tests are to be performed prior to installation of the system on the stack and may be performed at the affected facility or at other locations provided that proper notification is given. Set up and calibrate the measurement system as specified by the manufacturer's written instructions for the monitor pathlength to be used in the installation. Span the analyzer as specified in applicable subparts.

8.1.1 Calibration Error Test. Insert a series of calibration filters in the transmissometer path at the midpoint. A minimum of three calibration filters (low, mid, and high-range) selected in accordance with the table under paragraph 2.1 and calibrated within 3 percent must be used. Make a total of five nonconsecutive readings for each filter.

Record the measurement system output readings in percent opacity. (See Figure 1-1.)

8.1.2 System Response Test. Insert the high-range filter in the transmissometer path five times and record the time required for the system to respond to 95 percent of final zero and high-range filter values. (See Figure 1-2.)

8.2 Field Test for Zero Drift and Calibration Drift. Install the continuous monitoring system on the affected facility and perform the following alignments:

8.2.1 Preliminary Alignments. As soon as possible after installation and once a year thereafter when the facility is not in operation, perform the following optical and zero alignments:

8.2.1.1 Optical Alignment. Align the light beam from the transmissometer upon the optical surfaces located across the effluent (i.e., the retroflector or photodetector as applicable) in accordance with the manufacturer's instructions.

8.2.1.2 Zero Alignment. After the transmissometer has been optically aligned and the transmissometer mounting is mechanically stable (i.e., no movement of the mounting due to thermal contraction of the stack, duct, etc.) and a clean stack condition has been determined by a steady zero opacity condition, perform the zero alignment. This alignment is performed by balancing the continuous monitor system response so that any simulated zero check coincides with an actual zero check performed across the monitor pathlength of the clean stack.

8.2.1.3 Span. Span the continuous monitoring system at the opacity specified in subparts and offset the zero setting at least 10 percent of span so that negative drift can be quantified.

8.2.2. Final Alignments. After the preliminary alignments have been completed and the affected facility has been started up and reaches normal operating temperature, recheck the optical alignment in accordance with 8.2.1.1 of this specification. If the alignment has shifted, realign the optics, record any detectable shift in the opacity measured by the system that can be attributed to the optical realignment, and notify the Administrator. This condition may not be objectionable if the affected facility operates within a fairly constant and adequately narrow range of operating temperatures that does not produce significant shifts in optical alignment during normal operation of the facility. Under circumstances where the facility operations produce fluctuations in the effluent gas temperature that result in significant misalignments, the Administrator may require improved mounting structures or another location for installation of the transmissometer.

8.2.3 Conditioning Period. After completing the post-startup alignments, operate the system for an initial 168-hour conditioning period in a normal operational manner.

8.2.4 Operational Test Period. After completing the conditioning period, operate the system for an additional 168-hour period retaining the zero offset. The system shall monitor the source effluent at all times except when being zeroed or calibrated. At 24-hour intervals the zero and span shall be checked according to the manufacturer's instructions. Minimum procedures used shall provide a system check of the analyzer internal mirrors and all electronic circuitry including the lamp and photodetector assembly and shall include a procedure for producing a simulated zero opacity condition and a simulated upscale (span) opacity condition as viewed by the receiver. The manufacturer's written instructions may be used providing that they equal or exceed these minimum procedures. Zero and span the transmissometer, clean all optical surfaces exposed to the effluent, realign optics, and make any necessary adjustments to the calibration of the system daily. These zero and calibration adjustments and optical realignments are allowed only at 24-hour intervals or at such shorter intervals as the manufacturer's written instructions specify. Automatic corrections made by the measurement system without operator intervention are allowable at any time. The magnitude of any zero or span drift adjustments shall be recorded. During this 168-hour operational test period, record the following at 24-hour intervals: (a) the zero reading and span readings after the system is calibrated (these readings should be set at the same value at the beginning of each 24-hour period); (b) the zero reading after each 24 hours of operation, but before cleaning and adjustment; and (c) the span reading after cleaning and zero adjustment, but before span adjustment. (See Figure 1-3.)

9. Calculation, Data Analysis, and Reporting.

9.1 Procedure for Determination of Mean Values and Confidence Intervals.

9.1.1 The mean value of the data set is calculated according to equation 1-1.

$$\bar{x}=\frac{1}{n}\sum_{i=1}^{n}x_i \qquad \text{Equation 1-1}$$

where x_i = absolute value of the individual measurements,

Σ = sum of the individual values.
$\bar{x}$ = mean value, and
n = number of data points.

9.1.2 The 95 percent confidence interval (two-sided) is calculated according to equation 1-2:

$$C.I._{95}=\frac{t_{.975}}{n\sqrt{n-1}}\sqrt{n(\Sigma x_i^2)-(\Sigma x_i)^2} \qquad \text{Equation 1-2}$$

where

Σx_i = sum of all data points,
$t_{.975}=t_1-\alpha/2$, and
$C.I._{95}$ = 95 percent confidence interval estimate of the average mean value.

Values for $t_{.975}$

n	$t_{.975}$	n	$t_{.975}$
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

The values in this table are already corrected for n-1 degrees of freedom. Use n equal to the number of samples as data points.

9.2 Data Analysis and Reporting.

9.2.1 Spectral Response. Combine the spectral data obtained in accordance with paragraph 6.3.1 to develop the effective spectral response curve of the transmissometer. Report the wavelength at which the peak response occurs, the wavelength at which the mean response occurs, and the maximum response at any wavelength below 400 nm and above 700 nm expressed as a percentage of the peak response as required under paragraph 6.2.

9.2.2 Angle of View. Using the data obtained in accordance with paragraph 6.3.2, calculate the response of the receiver as a function of viewing angle in the horizontal and vertical directions (26 centimeters of arc with a radius of 3 meters equal 5 degrees). Report relative angle of view curves as required under paragraph 6.2.

9.2.3 Angle of Projection. Using the data obtained in accordance with paragraph 6.3.3, calculate the response of the photoelectric detector as a function of projection angle in the horizontal and vertical directions. Report relative angle of projection curves as required under paragraph 6.2.

9.2.4 Calibration Error. Using the data from paragraph 8.1 (Figure 1-1), subtract the known filter opacity value from the value shown by the measurement system for each of the 15 readings. Calculate the mean and 95 percent confidence interval of the five different values at each test filter value according to equations 1-1 and 1-2. Report the sum of the absolute mean difference and the 95 percent confidence interval for each of the three test filters.

9.2.5 Zero Drift. Using the zero opacity values measured every 24 hours during the field test (paragraph 8.2), calculate the differences between the zero point after cleaning, aligning, and adjustment, and the zero value 24 hours later just prior to cleaning, aligning, and adjustment. Calculate the mean value of these points and the confidence interval using equations 1-1 and 1-2. Report the sum of the absolute mean value and the 95 percent confidence interval.

9.2.6 Calibration Drift. Using the span value measured every 24 hours during the field test, calculate the differences between the span value after cleaning, aligning, and adjustment of zero and span, and the span value 24 hours later just after cleaning, aligning, and adjustment of zero and before adjustment of span. Calculate the mean value of these points and the confidence interval using equations 1-1 and 1-2. Report the sum of the absolute mean value and the confidence interval.

9.2.7 Response Time. Using the data from paragraph 8.1, calculate the time interval from filter insertion to 95 percent of the final stable value for all upscale and downscale traverses. Report the mean of the 10 upscale and downscale test times.

9.2.8 Operational Test Period. During the 168-hour operational test period, the continuous monitoring system shall not require any corrective maintenance, repair, replacement, or adjustment other than that clearly specified as required in the manufacturer's operation and maintenance manuals as routine and expected during a one-week period. If the continuous monitoring system is operated within the specified performance parameters and does not require corrective maintenance, repair, replacement, or adjustment other than as specified above during the 168-hour test period, the operational test period shall have been successfully concluded. Failure of the continuous monitoring system to meet these requirements shall call for a repetition of the 168-hour test period. Portions of the tests which were satisfactorily completed need not be repeated. Failure to meet any performance specification(s) shall call for a repetition of the one-week operational test period and that specific portion of the tests required by paragraph 8 related to demonstrating compliance with the failed specification. All maintenance and adjustments required shall be recorded. Output readings shall be recorded before and after all adjustments.

10. References.

10.1 "Experimental Statistics," Department of Commerce, National Bureau of Standards Handbook 91, 1963, pp. 3-31, paragraphs 3-3.1.4.

10.2 "Performance Specifications for Stationary-Source Monitoring Systems for Gases and Visible Emissions," Environmental Protection Agency, Research Triangle Park, N.C., EPA-650/2-74-013, January 1974.

Calibrated Neutral Density Filter Data
(See paragraph 8.1.1)

Low Range ____% opacity Span Value _____% opacity	Mid Range ___% opacity	High Range ___% opacity
Date of Test _____	Location of Test _____	

	Calibrated Filter[1]	Analyzer Reading % Opacity	Differences[2] % Opacity
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			

	Low	Mid	High
Mean difference	____	____	____
Confidence interval	____	____	____
Calibration error = Mean Difference[3] + C.I.	____	____	____

[1] Low, mid or high range
[2] Calibration filter opacity - analyzer reading
[3] Absolute value

Figure 1-1. Calibration Error Test

Date of Test _____ Location of Test _____
Span Filter _____ % Opacity
Analyzer Span Setting _____ % Opacity

Upscale	1	_____ seconds
	2	_____ seconds
	3	_____ seconds
	4	_____ seconds
	5	_____ seconds
Downscale	1	_____ seconds
	2	_____ seconds
	3	_____ seconds
	4	_____ seconds
	5	_____ seconds
Average response		_____ seconds

Figure 1-2. Response Time Test

Zero Setting _____ (See paragraph 8.2.1) Date of Test _____

Span Setting _____

Date and Time	Zero Reading (Before cleaning and adjustment)	Zero Drift (ΔZero)	Span Reading (After cleaning and zero adjustment but before span adjustment)	Calibration Drift (ΔSpan)

Zero Drift = Mean Zero Drift* _____ + CI (Zero) _____ = _____.

Calibration Drift = Mean Span Drift* _____ + CI (Span) _____ = _____.

*Absolute value

Figure 1-3. Zero and Calibration Drift Test

PERFORMANCE SPECIFICATION 2—PERFORMANCE SPECIFICATIONS AND SPECIFICATION TEST PROCEDURES FOR MONITORS OF SO_2 AND NO_x FROM STATIONARY SOURCES

1. Principle and Applicability.

1.1 Principle. The concentration of sulfur dioxide or oxides of nitrogen pollutants in stack emissions is measured by a continuously operating emission measurement system. Concurrent with operation of the continuous monitoring system, the pollutant concentrations are also measured with reference methods (Appendix A). An average of the continuous monitoring system data is computed for each reference method testing period and compared to determine the relative accuracy of the continuous monitoring system. Other tests of the continuous monitoring system are also performed to determine calibration error, drift, and response characteristics of the system.

1.2 Applicability. This performance specification is applicable to evaluation of continuous monitoring systems for measurement of nitrogen oxides or sulfur dioxide pollutants. These specifications contain test procedures, installation requirements, and data computation procedures for evaluating the acceptability of the continuous monitoring systems.

2. Apparatus.

2.1 Calibration Gas Mixtures. Mixtures of known concentrations of pollutant gas in a diluent gas shall be prepared. The pollutant gas shall be sulfur dioxide or the appropriate oxide(s) of nitrogen specified by paragraph 6 and within subparts. For sulfur dioxide gas mixtures, the diluent gas may be air or nitrogen. For nitric oxide (NO) gas mixtures, the diluent gas shall be oxygen-free (<10 ppm) nitrogen, and for nitrogen dioxide (NO_2) gas mixtures the diluent gas shall be air. Concentrations of approximately 50 percent and 90 percent of span are required. The 90 percent gas mixture is used to set and to check the span and is referred to as the span gas.

2.2 Zero Gas. A gas certified by the manufacturer to contain less than 1 ppm of the pollutant gas or ambient air may be used.

2.3 Equipment for measurement of the pollutant gas concentration using the reference method specified in the applicable standard.

2.4 Data Recorder. Analog chart recorder or other suitable device with input voltage range compatible with analyzer system output. The resolution of the recorder's data output shall be sufficient to allow completion of the test procedures within this specification.

2.5 Continuous monitoring system for SO_2 or NO_x pollutants as applicable.

3. Definitions.

3.1 Continuous Monitoring System. The total equipment required for the determination of a pollutant gas concentration in a source effluent. Continuous monitoring systems consist of major subsystems as follows:

3.1.1 Sampling Interface—That portion of an extractive continuous monitoring system that performs one or more of the following operations: acquisition, transportation, and conditioning of a sample of the source effluent or that portion of an in-situ continuous monitoring system that protects the analyzer from the effluent.

3.1.2 Analyzer—That portion of the continuous monitoring system which senses the pollutant gas and generates a signal output that is a function of the pollutant concentration.

3.1.3 Data Recorder—That portion of the continuous monitoring system that provides a permanent record of the output signal in terms of concentration units.

3.2 Span. The value of pollutant concentration at which the continuous monitoring system is set to produce the maximum data display output. The span shall be set at the concentration specified in each applicable subpart.

3.3 Accuracy (Relative) The degree of correctness with which the continuous monitoring system yields the value of gas concentration of a sample relative to the value given by a defined reference method. This accuracy is expressed in terms of error, which is the difference between the paired concentration measurements expressed as a percentage of the mean reference value.

3.4 Calibration Error. The difference between the pollutant concentration indicated by the continuous monitoring system and the known concentration of the test gas mixture.

3.5 Zero Drift. The change in the continuous monitoring system output over a stated period of time of normal continuous operation when the pollutant concentration at the time for the measurements is zero.

3.6 Calibration Drift. The change in the continuous monitoring system output over a stated time period of normal continuous operations when the pollutant concentration at the time of the measurements is the same known upscale value.

3.7 Response Time. The time interval from a step change in pollutant concentration at the input to the continuous monitoring system to the time at which 95 percent of the corresponding final value is reached as displayed on the continuous monitoring system data recorder.

3.8 Operational Period. A minimum period of time over which a measurement system is expected to operate within certain performance specifications without unscheduled maintenance, repair, or adjustment.

3.9 Stratification. A condition identified by a difference in excess of 10 percent between the average concentration in the duct or stack and the concentration at any point more than 1.0 meter from the duct or stack wall.

4. Installation Specifications. Pollutant continuous monitoring systems (SO_2 and NO_x) shall be installed at a sampling location where measurements can be made which are directly representative (4.1), or which can be corrected so as to be representative (4.2) of the total emissions from the affected facility. Conformance with this requirement shall be accomplished as follows:

4.1 Effluent gases may be assumed to be nonstratified if a sampling location eight or more stack diameters (equivalent diameters) downstream of any air in-leakage is selected. This assumption and data correction procedures under paragraph 4.2.1 may not be applied to sampling locations upstream of an air preheater in a stream generating facility under Subpart D of this part. For sampling locations where effluent gases are either demonstrated (4.3) or may be assumed to be nonstratified (eight diameters), a point (extractive systems) or path (in-situ systems) of average concentration may be monitored.

4.2 For sampling locations where effluent gases cannot be assumed to be nonstratified (less than eight diameters) or have been shown under paragraph 4.3 to be stratified, results obtained must be consistently representative (e.g. a point of average concentration may shift with load changes) or the data generated by sampling at a point (extractive systems) or across a path (in-situ systems) must be corrected (4.2.1 and 4.2.2) so as to be representative of the total emissions from the affected facility. Conformance with this requirement may be accomplished in either of the following ways:

4.2.1 Installation of a diluent continuous monitoring system (O_2 or CO_2 as applicable) in accordance with the procedures under paragraph 4.2 of Performance Specification 3 of this appendix. If the pollutant and diluent monitoring systems are not of the same type (both extractive or both in-situ), the extractive system must use a multipoint probe.

4.2.2 Installation of extractive pollutant monitoring systems using multipoint sampling probes or in-situ pollutant monitoring systems that sample or view emissions which are consistently representative of the total emissions for the entire cross section. The Administrator may require data to be sub-

mitted to demonstrate that the emissions sampled or viewed are consistently representative for several typical facility process operating conditions.

4.3 The owner or operator may perform a traverse to characterize any stratification of effluent gases that might exist in a stack or duct. If no stratification is present, sampling procedures under paragraph 4.1 may be applied even though the eight diameter criteria is not met.

4.4 When single point sampling probes for extractive systems are installed within the stack or duct under paragraphs 4.1 and 4.2.1, the sample may not be extracted at any point less than 1.0 meter from the stack or duct wall. Multipoint sampling probes installed under paragraph 4.2.2 may be located at any points necessary to obtain consistently representative samples.

5. *Continuous Monitoring System Performance Specifications.*

The continuous monitoring system shall meet the performance specifications in Table 2-1 to be considered acceptable under this method.

TABLE 2-1.—*Performance specifications*

Parameter	*Specification*
1. Accuracy [1]	≤20 pct of the mean value of the reference method test data.
2. Calibration error [1]	≤ 5 pct of each (50 pct, 90 pct) calibration gas mixture value.
3. Zero drift (2 h) [1]	2 pct of span
4. Zero drift (24 h) [1]	Do.
5. Calibration drift (2 h) [1]	Do.
6. Calibration drift (24 h) [1]	2.5 pct. of span
7. Response time	15 *min* maximum.
8. Operational period	168 h minimum.

[1] Expressed as sum of absolute mean value plus 95 pct confidence interval of a series of tests.

6. Performance Specification Test Procedures. The following test procedures shall be used to determine conformance with the requirements of paragraph 5. For NO_x anrequirements of paragraph 5. For NO_x analyzers that oxidize nitric oxide (NO) to nitrogen dioxide (NO_2), the response time test under paragraph 6.3 of this method shall be performed using nitric oxide (NO) span gas. Other tests for NO_x continuous monitoring systems under paragraphs 6.1 and 6.2 and all tests for sulfur dioxide systems shall be performed using the pollutant span gas specified by each subpart.

6 1 Calibration Error Test Procedure. Set up and calibrate the complete continuous monitoring system according to the manufacturer's writen instructions. This may be accomplished either in the laboratory or in the field.

6.1.1 Calibration Gas Analyses. Triplicate analyses of the gas mixtures shall be performed within two weeks prior to use using Reference Methods 6 for SO_2 and 7 for NO_x. Analyze each calibration gas mixture (50%, 90%) and record the results on the example sheet shown in Figure 2-1. Each sample test result must be within 20 percent of the averaged result or the tests shall be repeated. This step may be omitted for non-extractive monitors where dynamic calibration gas mixtures are not used (6.1.2).

6 1.2 *Calibration Error Test Procedure.* Make a total of 15 nonconsecutive measurements by alternately using zero gas and each caliberation gas mixture concentration (e.g., 0%, 50%, 0%, 90%, 50%, 90%, 50%, 0%, etc.). For nonextractive continuous monitoring systems, this test procedure may be performed by using two or more calibration gas cells whose concentrations are certified by the manufacturer to be functionally equivalent to these gas concentrations. Convert the continuous monitoring system output readings to ppm and record the results on the example sheet shown in Figure 2-2.

6.2 Field Test for Accuracy (Relative), Zero Drift, and Calibration Drift. Install and operate the continuous monitoring system in accordance with the manufacturer's written instructions and drawings as follows:

6.2.1 Conditioning Period. Offset the zero setting at least 10 percent of the span so that negative zero drift can be quantified. Operate the system for an initial 168-hour conditioning period in normal operating manner.

6.2.2 Operational Test Period. Operate the continuous monitoring system for an additional 168-hour period retaining the zero offset. The system shall monitor the source effluent at all times except when being zeroed, calibrated, or backpurged.

6.2.2.1 Field Test for Accuracy (Relative) For continuous monitoring systems employing extractive sampling, the probe tip for the continuous monitoring system and the probe tip for the Reference Method sampling train should be placed at adjacent locations in the duct. For NO_x continuous monitoring systems, make 27 NO_x concentration measurements, divided into nine sets, using the applicable reference method. No more than one set of tests, consisting of three individual measurements, shall be performed in any one hour. All individual measurements of each set shall be performed concurrently, or within a three-minute interval and the results averaged. For SO_2 continuous monitoring systems, make nine SO_2 concentration measurements using the applicable reference method. No more than one measurement shall be performed in any one hour. Record the reference method test data and the continuous monitoring system concentrations on the example data sheet shown in Figure 2-3.

6.2.2.2 Field Test for Zero Drift and Calibration Drift. For extractive systems, determine the values given by zero and span gas pollutant concentrations at two-hour intervals until 15 sets of data are obtained. For nonextractive measurement systems, the zero value may be determined by mechanically producing a zero condition that provides a system check of the analyzer internal mirrors and all electronic circuitry including the radiation source and detector assembly or by inserting three or more calibration gas cells and computing the zero point from the upscale measurements. If this latter technique is used, a graph(s) must be retained by the owner or operator for each measurement system that shows the relationship between the upscale measurements and the zero point. The span of the system shall be checked by using a calibration gas cell certified by the manufacturer to be functionally equivalent to 50 percent of span concentration. Record the zero and span measurements (or the computed zero drift) on the example data sheet shown in Figure 2-4. The two-hour periods over which measurements are conducted need not be consecutive but may not overlap. All measurements required under this paragraph may be conducted concurrent with tests under paragraph 6.2.2.1.

6.2.2.3 Adjustments. Zero and calibration corrections and adjustments are allowed only at 24-hour intervals or at such shorter intervals as the manufacturer's written instructions specify. Automatic corrections made by the measurement system without operator intervention or initiation are allowable at any time. During the entire 168-hour operational test period, record on the example sheet shown in Figure 2-5 the values given by zero and span gas pollutant concentrations before and after adjustment at 24-hour intervals.

6.3 Field Test for Response Time

6.3.1 Scope of Test. Use the entire continuous monitoring system as installed, including sample transport lines if used. Flow rates, line diameters, pumping rates, pressures (do not allow the pressurized calibration gas to change the normal operating pressure in the sample line), etc., shall be at the nominal values for normal operation as specified in the manufacturer's written instructions. If the analyzer is used to sample more than one pollutant source (stack), repeat this test for each sampling point.

6.3.2 Response Time Test Procedure. Introduce zero gas into the continuous monitoring system sampling interface or as close to the sampling interface as possible. When the system output reading has stabilized, switch quickly to a known concentration of pollutant gas. Record the time from concentration switching to 95 percent of final stable response. For non-extractive monitors, the highest available calibration gas concentration shall be switched into and out of the sample path and response times recorded. Perform this test sequence three (3) times. Record the results of each test on the example sheet shown in Figure 2-6.

7. Calculations, Data Analysis and Reporting.

7.1 Procedure for determination of mean values and confidence intervals.

7.1.1 The mean value of a data set is calculated according to equation 2-1.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i \qquad \text{Equation 2-1}$$

where:

x_i = absolute value of the measurements,
Σ = sum of the individual values,
$\bar{x}$ = mean value, and
n = number of data points.

7.1.2 The 95 percent confidence interval (two-sided) is calculated according to equation 2-2:

$$C.I._{95} = \frac{t_{.975}}{n\sqrt{n-1}}\sqrt{n(\Sigma x_i^2) - (\Sigma x_i)^2} \qquad \text{Equation 2-2}$$

where:

Σx_i = sum of all data points,
$t_{.975} = t_{1-\alpha/2}$, and
$C.I._{95}$ = 95 percent confidence interval estimate of the average mean value.

Values for $t_{.975}$

	$t_{.975}$
1	12.706
2	4.303
3	3.182
4	2.776
5	2.571
6	2.447
7	2.365
8	2.306
9	2.262
10	2.228
12	2.201
13	2.179
14	2.160
15	2.145
16	2.131

The values in this table are already corrected for n-1 degrees of freedom. Use n

equal to the number of samples as data points.

7.2 Data Analysis and Reporting.

7.2.1 Accuracy (Relative). For each of the nine reference method test points, determine the average pollutant concentration reported by the continuous monitoring system. These average concentrations shall be determined from the continuous monitoring system data recorded under 7.2.2 by integrating or averaging the pollutant concentrations over each of the time intervals concurrent with each reference method testing period. Before proceeding to the next step, determine the basis (wet or dry) of the continuous monitoring system data and reference method test data concentrations. If the bases are not consistent, apply a moisture correction to either reference method concentrations or the continuous monitoring system concentrations as appropriate. Determine the correction factor by moisture tests concurrent with the reference method testing periods. Report the moisture test method and the correction procedure employed. For each of the nine test runs determine the difference for each test run by subtracting the respective reference method test concentrations (use average of each set of three measurements for NO_x) from the continuous monitoring system integrated or averaged concentrations. Using these data, compute the mean difference and the 95 percent confidence interval of the differences (equations 2-1 and 2-2). Accuracy is reported as the sum of the absolute value of the mean difference and the 95 percent confidence interval of the differences expressed as a percentage of the mean reference method value. Use the example sheet shown in Figure 2-3.

7.2.2 Calibration Error. Using the data from paragraph 6.1, subtract the measured pollutant concentration determined under paragraph 6.1.1 (Figure 2-1) from the value shown by the continuous monitoring system for each of the five readings at each concentration measured under 6.1.2 (Figure 2-2). Calculate the mean of these difference values and the 95 percent confidence intervals according to equations 2-1 and 2-2. Report the calibration error (the sum of the absolute value of the mean difference and the 95 percent confidence interval) as a percentage of each respective calibration gas concentration. Use example sheet shown in Figure 2-2.

7.2.3 Zero Drift (2-hour). Using the zero concentration values measured each two hours during the field test, calculate the differences between consecutive two-hour readings expressed in ppm. Calculate the mean difference and the confidence interval using equations 2-1 and 2-2. Report the zero drift as the sum of the absolute mean value and the confidence interval as a percentage of span. Use example sheet shown in Figure 2-4.

7.2.4 Zero Drift (24-hour). Using the zero concentration values measured every 24 hours during the field test, calculate the differences between the zero point after zero adjustment and the zero value 24 hours later just prior to zero adjustment. Calculate the mean value of these points and the confidence interval using equations 2-1 and 2-2. Report the zero drift (the sum of the absolute mean and confidence interval) as a percentage of span. Use example sheet shown in Figure 2-5.

7.2.5 Calibration Drift (2-hour). Using the calibration values obtained at two-hour intervals during the field test, calculate the differences between consecutive two-hour readings expressed as ppm. These values should be corrected for the corresponding zero drift during that two-hour period. Calculate the mean and confidence interval of these corrected difference values using equations 2-1 and 2-2. Do not use the differences between non-consecutive readings. Report the calibration drift as the sum of the absolute mean and confidence interval as a percentage of span. Use the example sheet shown in Figure 2-4.

7.2.6 Calibration Drift (24-hour). Using the calibration values measured every 24 hours during the field test, calculate the differences between the calibration concentration reading after zero and calibration adjustment, and the calibration concentration reading 24 hours later after zero adjustment but before calibration adjustment. Calculate the mean value of these differences and the confidence interval using equations 2-1 and 2-2. Report the calibration drift (the sum of the absolute mean and confidence interval) as a percentage of span. Use the example sheet shown in Figure 2-5.

7.2.7 Response Time. Using the charts from paragraph 6.3, calculate the time interval from concentration switching to 95 percent to the final stable value for all upscale and downscale tests. Report the mean of the three upscale test times and the mean of the three downscale test times. The two average times should not differ by more than 15 percent of the slower time. Report the slower time as the system response time. Use the example sheet shown in Figure 2-6.

7.2.8 Operational Test Period. During the 168-hour performance and operational test period, the continuous monitoring system shall not require any corrective maintenance, repair, replacement, or adjustment other than that clearly specified as required in the operation and maintenance manuals as routine and expected during a one-week period. If the continuous monitoring system operates within the specified performance parameters and does not require corrective maintenance, repair, replacement or adjustment other than as specified above during the 168-hour test period, the operational period will be successfully concluded. Failure of the continuous monitoring system to meet this requirement shall call for a repetition of the 168-hour test period. Portions of the test which were satisfactorily completed need not be repeated. Failure to meet any performance specifications shall call for a repetition of the one-week performance test period and that portion of the testing which is related to the failed specification. All maintenance and adjustments required shall be recorded. Output readings shall be recorded before and after all adjustments.

8. References.

8.1 "Monitoring Instrumentation for the Measurement of Sulfur Dioxide in Stationary Source Emissions," Environmental Protection Agency, Research Triangle Park, N.C., February 1973.

8.2 "Instrumentation for the Determination of Nitrogen Oxides Content of Stationary Source Emissions," Environmental Protection Agency, Research Triangle Park, N.C., Volume 1, APTD-0847, October 1971; Volume 2, APTD-0942, January 1972.

8.3 "Experimental Statistics," Department of Commerce, Handbook 91, 1963, pp. 3-31, paragraphs 3-3.1.4.

8.4 "Performance Specifications for Stationary-Source Monitoring Systems for Gases and Visible Emissions," Environmental Protection Agency, Research Triangle Park, N.C., EPA-650/2-74-013, January 1974.

Date _____ Reference Method Used ___

Mid-Range Calibration Gas Mixture

Sample 1 _____ ppm

Sample 2 _____ ppm

Sample 3 _____ ppm

Average _____ ppm

High-Range (span) Calibration Gas Mixture

Sample 1 _____ ppm

Sample 2 _____ ppm

Sample 3 _____ ppm

Average _____ ppm

Figure 2-1. Analysis of Calibration Gas Mixtures

Calibration Gas Mixture Data (From Figure 2-1)

Mid (50%) _____ ppm High (90%) _____ ppm

Run #	Calibration Gas Concentration, ppm	Measurement System Reading, ppm	Differences,[1] ppm
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			

	Mid	High
Mean difference	____	____
Confidence interval	+____	+____

Calibration error = $\frac{\text{Mean Difference}^{2} + \text{C.I.}}{\text{Average Calibration Gas Concentration}} \times 100$ ____% ____%

[1] Calibration gas concentration - measurement system reading

[2] Absolute value

Figure 2-2. Calibration Error Determination

Test No.	Date and Time	Reference Method Samples: SO_2 Sample 1 (ppm)	NO_x Sample 1 (ppm)	NO_x Sample 2 (ppm)	NO_x Sample 3 (ppm)	NO_x Sample Average (ppm)	Analyzer 1-Hour Average (ppm)* SO_2	Analyzer 1-Hour Average (ppm)* NO_x	Difference (ppm) SO_2	Difference (ppm) NO_x
1										
2										
3										
4										
5										
6										
7										
8										
9										

Mean reference method test value (SO_2) _____ Mean reference method test value (NO_x) _____ Average of the differences _____

Mean differences** = _____ ppm (SO_2), = _____ ppm (NO_x).

95% Confidence intervals = = ± _____ ppm (SO_2), = ± _____ ppm (NO_x).

Accuracies = $\frac{\text{Mean difference (absolute value)} + \text{95\% confidence interval}}{\text{Mean reference method value}} \times 100$ = ____% (SO_2), = ____% (NO_x)

* Explain and report method used to determine integrated averages.

** Mean differences = the average of the differences minus the mean reference method test value.

Figure 2-3. Accuracy Determination (SO_2 and NO_x)

Data Set No.	Time Begin	Time End	Date	Zero Reading	Zero Drift (ΔZero)	Span Reading	Span Drift (ΔSpan)	Calibration Drift (Span- Zero)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								

Zero Drift = [Mean Zero Drift* _____ + CI (Zero) _____] ÷ [Span] x 100 = _____.
Calibration Drift = [Mean Span Drift* _____ + CI (Span) _____] ÷ [Span] x 100 = _____.
*Absolute Value.

Figure 2-4. Zero and Calibration Drift (2 hour)

Date and Time	Zero Reading	Zero Drift (ΔZero)	Span Reading (After zero adjustment)	Calibration Drift (ΔSpan)

Zero Drift = [Mean Zero Drift* _____ + C.I. (Zero) _____]
÷ [Instrument Span] x 100 = _____.

Calibration Drift = [Mean Span Drift* _____ + C.I. (Span) _____]
÷ [Instrument Span] x 100 = _____.

* Absolute value

Figure 2-5. Zero and Calibration Drift (24-hour)

Date of Test _____

Span Gas Concentration _____ppm

Analyzer Span Setting _____ppm

Upscale	1 _____	seconds
	2 _____	seconds
	3 _____	seconds
	Average upscale response _____	seconds
Downscale	1 _____	seconds
	2 _____	seconds
	3 _____	seconds
	Average downscale response _____	seconds

System average response time (slower time) = _____seconds

$$\%\text{deviation from slower system average response} = \left[\frac{\text{average upscale minus average downscale}}{\text{slower time}}\right] \times 100\% = ____$$

Figure 2-6. Response Time

Performance Specification 3—Performance specifications and specification test procedures for monitors of CO_2 and O_2 from stationary sources.

1. Principle and Applicability.

1.1 Principle. Effluent gases are continuously sampled and are analyzed for carbon dioxide or oxygen by a continuous monitoring system. Tests of the system are performed during a minimum operating period to determine zero drift, calibration drift, and response time characteristics.

1 2 Applicability. This performance specification is applicable to evaluation of continuous monitoring systems for measurement of carbon dioxide or oxygen. These specifications contain test procedures, installation requirements, and data computation procedures for evaluating the acceptability of the continuous monitoring systems subject to approval by the Administrator. Sampling may include either extractive or non-extractive (in-situ) procedures.

2. Apparatus.

2.1 Continuous Monitoring System for Carbon Dioxide or Oxygen.

2 2 Calibration Gas Mixtures. Mixture of known concentrations of carbon dioxide or oxygen in nitrogen or air. Midrange and 90 percent of span carbon dioxide or oxygen concentrations are required. The 90 percent of span gas mixture is to be used to set and check the analyzer span and is referred to as span gas. For oxygen analyzers, if the span is higher than 21 percent O_2, ambient air may be used in place of the 90 percent of span calibration gas mixture. Triplicate analyses of the gas mixture (except ambient air) shall be performed within two weeks prior to use using Reference Method 3 of this part.

2.3 Zero Gas. A gas containing less than 100 ppm of carbon dioxide or oxygen.

2.4 Data Recorder. Analog chart recorder or other suitable device with input voltage range compatible with analyzer system output. The resolution of the recorder's data output shall be sufficient to allow completion of the test procedures within this specification.

3. Definitions.

3.1 Continuous Monitoring System. The total equipment required for the determination of carbon dioxide or oxygen in a given source effluent. The system consists of three major subsystems:

3 1.1 Sampling Interface. That portion of the continuous monitoring system that performs one or more of the following operations: delineation, acquisition, transportation, and conditioning of a sample of the source effluent or protection of the analyzer from the hostile aspects of the sample or source environment.

3 1.2 Analyzer. That portion of the continuous monitoring system which senses the pollutant gas and generates a signal output that is a function of the pollutant concentration.

3.1.3 Data Recorder. That portion of the continuous monitoring system that provides a permanent record of the output signal in terms of concentration units.

3.2 Span. The value of oxygen or carbon dioxide concentration at which the continuous monitoring system is set that produces the maximum data display output. For the purposes of this method, the span shall be set no less than 1.5 to 2.5 times the normal carbon dioxide or normal oxygen concentration in the stack gas of the affected facility.

3.3 Midrange. The value of oxygen or carbon dioxide concentration that is representative of the normal conditions in the stack gas of the affected facility at typical operating rates.

3.4 Zero Drift. The change in the continuous monitoring system output over a stated period of time of normal continuous operation when the carbon dioxide or oxygen concentration at the time for the measurements is zero.

3.5 Calibration Drift. The change in the continuous monitoring system output over a stated time period of normal continuous operation when the carbon dioxide or oxygen continuous monitoring system is measuring the concentration of span gas.

3.6 Operational Test Period. A minimum period of time over which the continuous monitoring system is expected to operate within certain performance specifications without unscheduled maintenance, repair, or adjustment.

3.7 Response time. The time interval from a step change in concentration at the input to the continuous monitoring system to the time at which 95 percent of the corresponding final value is displayed on the continuous monitoring system data recorder.

4. Installation Specification.

Oxygen or carbon dioxide continuous monitoring systems shall be installed at a location where measurements are directly representative of the total effluent from the affected facility or representative of the same effluent sampled by a SO_2 or NO_x continuous monitoring system. This requirement shall be complied with by use of applicable requirements in Performance Specification 2 of this appendix as follows:

4.1 Installation of Oxygen or Carbon Dioxide Continuous Monitoring Systems Not Used to Convert Pollutant Data. A sampling location shall be selected in accordance with the procedures under paragraphs 4.2.1 or 4.2.2, or Performance Specification 2 of this appendix.

4.2 Installation of Oxygen or Carbon Dioxide Continuous Monitoring Systems Used to Convert Pollutant Continuous Monitoring System Data to Units of Applicable Standards. The diluent continuous monitoring system (oxygen or carbon dioxide) shall be installed at a sampling location where measurements that can be made are representative of the effluent gases sampled by the pollutant continuous monitoring system(s). Conformance with this requirement may be accomplished in any of the following ways:

4.2.1 The sampling location for the diluent system shall be near the sampling location for the pollutant continuous monitoring system such that the same approximate point(s) (extractive systems) or path (in-situ systems) in the cross section is sampled or viewed.

4.2 2 The diluent and pollutant continuous monitoring systems may be installed at different locations if the effluent gases at both sampling locations are nonstratified as determined under paragraphs 4.1 or 4.3, Performance Specification 2 of this appendix and there is no in-leakage occurring between the two sampling locations. If the effluent gases are stratified at either location, the procedures under paragraph 4.2.2, Performance Specification 2 of this appendix shall be used for installing continuous monitoring systems at that location.

5. Continuous Monitoring System Performance Specifications.

The continuous monitoring system shall meet the performance specifications in Table 3-1 to be considered acceptable under this method.

6. Performance Specification Test Procedures.

The following test procedures shall be used to determine conformance with the requirements of paragraph 4. Due to the wide variation existing in analyzer designs and principles of operation, these procedures are not applicable to all analyzers. Where this occurs, alternative procedures, subject to the approval of the Administrator, may be employed. Any such alternative procedures must fulfill the same purposes (verify response, drift, and accuracy) as the following procedures, and must clearly demonstrate conformance with specifications in Table 3-1.

6.1 Calibration Check. Establish a calibration curve for the continuous monitoring system using zero, midrange, and span concentration gas mixtures. Verify that the resultant curve of analyzer reading compared with the calibration gas value is consistent with the expected response curve as described by the analyzer manufacturer. If the expected response curve is not produced, additional calibration gas measurements shall be made, or additional steps undertaken to verify

the accuracy of the response curve of the analyzer.

6.2 Field Test for Zero Drift and Calibration Drift. Install and operate the continuous monitoring system in accordance with the manufacturer's written instructions and drawings as follows:

TABLE 3-1.—*Performance specifications*

Parameter	Specification
1. Zero drift (2 h) [1]	≤0.4 pct O_2 or CO_2.
2. Zero drift (24 h) [1]	≤0.5 pct O_2 or CO_2.
3. Calibration drift (2 h) [1]	≤0.4 pct O_2 or CO_2.
4. Calibration drift (24 h) [1]	≤0.5 pct O_2 or CO_2.
5. Operational period	168 h minimum.
6. Response time	10 min.

[1] Expressed as sum of absolute mean value plus 95 pct confidence interval of a series of tests.

6.2.1 Conditioning Period. Offset the zero setting at least 10 percent of span so that negative zero drift may be quantified. Operate the continuous monitoring system for an initial 168-hour conditioning period in a normal operational manner.

6.2.2. Operational Test Period. Operate the continuous monitoring system for an additional 168-hour period maintaining the zero offset. The system shall monitor the source effluent at all times except when being zeroed, calibrated, or backpurged.

6.2.3 Field Test for Zero Drift and Calibration Drift. Determine the values given by zero and midrange gas concentrations at two-hour intervals until 15 sets of data are obtained. For non-extractive continuous monitoring systems, determine the zero value given by a mechanically produced zero condition or by computing the zero value from upscale measurements using calibrated gas cells certified by the manufacturer. The midrange checks shall be performed by using certified calibration gas cells functionally equivalent to less than 50 percent of span. Record these readings on the example sheet shown in Figure 3-1. These two-hour periods need not be consecutive but may not overlap. In-situ CO_2 or O_2 analyzers which cannot be fitted with a calibration gas cell may be calibrated by alternative procedures acceptable to the Administrator. Zero and calibration corrections and adjustments are allowed only at 24-hour intervals or at such shorter intervals as the manufacturer's written instructions specify. Automatic corrections made by the continuous monitoring system without operator intervention or initiation are allowable at any time. During the entire 168-hour test period, record the values given by zero and span gas concentrations before and after adjustment at 24-hour intervals in the example sheet shown in Figure 3-2.

6.3 Field Test for Response Time.

6.3.1 Scope of Test.

This test shall be accomplished using the continuous monitoring system as installed, including sample transport lines if used. Flow rates, line diameters, pumping rates, pressures (do not allow the pressurized calibration gas to change the normal operating pressure in the sample line), etc., shall be at the nominal values for normal operation as specified in the manufacturer's written instructions. If the analyzer is used to sample more than one source (stack), this test shall be repeated for each sampling point.

6.3.2 Response Time Test Procedure.

Introduce zero gas into the continuous monitoring system sampling interface or as close to the sampling interface as possible. When the system output reading has stabilized, switch quickly to a known concentration of gas at 90 percent of span. Record the time from concentration switching to 95 percent of final stable response. After the system response has stabilized at the upper level, switch quickly to a zero gas. Record the time from concentration switching to 95 percent of final stable response. Alternatively, for nonextractive continuous monitoring systems, the highest available calibration gas concentration shall be switched into and out of the sample path and response times recorded. Perform this test sequence three (3) times. For each test, record the results on the data sheet shown in Figure 3-3.

7. Calculations, Data Analysis, and Reporting.

7.1 Procedure for determination of mean values and confidence intervals.

7.1.1 The mean value of a data set is calculated according to equation 3-1.

$$\bar{x}=\frac{1}{n}\sum_{i=1}^{n}x_i \qquad \text{Equation 3-1}$$

where:

x_i = absolute value of the measurements,
Σ = sum of the individual values,
$\bar{x}$ = mean value, and
n = number of data points.

7.2.1 The 95 percent confidence interval (two-sided) is calculated according to equation 3-2:

$$C.I._{95}=\frac{t_{.975}}{n\sqrt{n-1}}\sqrt{n(\Sigma x_i^2)-(\Sigma x_i)^2} \qquad \text{Equation 3-2}$$

where:

ΣX = sum of all data points,
$t_{.975}=t_{1-\alpha/2}$, and
$C.I._{95}$ = 95 percent confidence interval estimated of the average mean value. value.

Values for $t_{.975}$

n	$t_{.975}$
2	12.706
3	4.303
4	3.182
5	2.776
6	2.571
7	2.447
8	2.365
9	2.306
10	2.262
11	2.228
12	2.201
13	2.179
14	2.160
15	2.145
16	2.131

The values in this table are already corrected for n-1 degrees of freedom. Use n equal to the number of samples as data points.

7.2 Data Analysis and Reporting.

7.2.1 Zero Drift (2-hour). Using the zero concentration values measured each two hours during the field test, calculate the differences between the consecutive two-hour readings expressed in ppm. Calculate the mean difference and the confidence interval using equations 3-1 and 3-2. Record the sum of the absolute mean value and the confidence interval on the data sheet shown in Figure 3-1.

7.2.2 Zero Drift (24-hour). Using the zero concentration values measured every 24 hours during the field test, calculate the differences between the zero point after zero adjustment and the zero value 24 hours later just prior to zero adjustment. Calculate the mean value of these points and the confidence interval using equations 3-1 and 3-2. Record the zero drift (the sum of the absolute mean and confidence interval) on the data sheet shown in Figure 3-2.

7.2.3 Calibration Drift (2-hour). Using the calibration values obtained at two-hour intervals during the field test, calculate the differences between consecutive two-hour readings expressed as ppm. These values should be corrected for the corresponding zero drift during that two-hour period. Calculate the mean and confidence interval of these corrected difference values using equations 3-1 and 3-2. Do not use the differences between non-consecutive readings. Record the sum of the absolute mean and confidence interval upon the data sheet shown in Figure 3-1.

7.2.4 Calibration Drift (24-hour). Using the calibration values measured every 24 hours during the field test, calculate the differences between the calibration concentration reading after zero and calibration adjustment and the calibration concentration reading 24 hours later after zero adjustment but before calibration adjustment. Calculate the mean value of these differences and the confidence interval using equations 3-1 and 3-2. Record the sum of the absolute mean and confidence interval on the data sheet shown in Figure 3-2.

7.2.5 Operational Test Period. During the 168-hour performance and operational test period, the continuous monitoring system shall not receive any corrective maintenance, repair, replacement, or adjustment other than that clearly specified as required in the manufacturer's written operation and maintenance manuals as routine and expected during a one-week period. If the continuous monitoring system operates within the specified performance parameters and does not require corrective maintenance, repair, replacement or adjustment other than as specified above during the 168-hour test period, the operational period will be successfully concluded. Failure of the continuous monitoring system to meet this requirement shall call for a repetition of the 168 hour test period. Portions of the test which were satisfactorily completed need not be repeated. Failure to meet any performance specifications shall call for a repetition of the one-week performance test period and that portion of the testing which is related to the failed specification. All maintenance and adjustments required shall be recorded. Output readings shall be recorded before and after all adjustments.

7.2.6 Response Time. Using the data developed under paragraph 5.3, calculate the time interval from concentration switching to 95 percent to the final stable value for all upscale and downscale tests. Report the mean of the three upscale test times and the mean of the three downscale test times. The two average times should not differ by more than 15 percent of the slower time. Report the slower time as the system response time. Record the results on Figure 3-3.

8. References.

8.1 "Performance Specifications for Stationary Source Monitoring Systems for Gases and Visible Emissions," Environmental Protection Agency, Research Triangle Park, N.C., EPA-650/2-74-013, January 1974.

8.2 "Experimental Statistics," Department of Commerce, National Bureau of Standards Handbook 91, 1963, pp. 3-31, paragraphs 3-3.1.4.

(Secs. 111 and 114 of the Clean Air Act, as amended by sec. 4(a) of Pub. L. 91-604, 84 Stat. 1678 (42 U.S.C. 1857c-6, by sec. 15(c)(2) of Pub. L. 91-604, 85 Stat. 1713 (42 U.S.C. 1857g)).

and submit plans containing emission standards for control of that pollutant from designated facilities [§ 60.23(a)]. For health-related pollutants, State emission standards must ordinarily be at least as stringent as the corresponding EPA guidelines to be approvable [§ 60.24 (c)]. However, States may apply less stringent standards to particular sources (or classes of sources) when economic factors or physical limitations specific to particular sources (or classes of sources) make such application significantly more reasonable [§ 60.24(f)]. For welfare-related pollutants, States may balance the emission guidelines and other information provided in EPA's guideline documents against other factors of public concern in establishing their emission standards, provided that appropriate consideration is given to the information presented in the guideline documents and at public hearings and that other requirements of Subpart B are met [§ 60.24(d)].

Within four months after the date required for submission of a plan, the Administrator will approve or disapprove the plan or portions thereof [§ 60.27(b)]. If a State plan (or portion thereof) is disapproved, the Administrator will promulgate a plan (or portion thereof) within 6 months after the date required for plan submission [§ 60.27(d)]. The plan submittal, approval/disapproval, and promulgation procedures are basically patterned after section 110 of the Act and 40 CFR Part 51 (concerning adoption and submittal of State implementation plans under section 110).

For health-related pollutants, the emission guidelines and compliance times referred to above will appear in a new Subpart C of Part 60. As indicated previously, emission guidelines and compliance times for welfare-related pollutants will appear only in the guideline documents published under § 60.22(a). Approvals and disapprovals of State plans and any plans (or portions thereof) promulgated by the Administrator will appear in a new Part 62.

Comments Received on Proposed Regulations and Changes Made in Final Regulations

Many of the comment letters received by EPA contained multiple comments. The most significant comments and differences between the proposed and final regulations are discussed below. Copies of the comment letters and a summary of the comments with EPA's responses (entitled "Public Comment Summary: Section 111(d) Regulations") are available for public inspection and copying at the EPA Public Information Reference Unit, Room 2922 (EPA Library), 401 M Street, SW., Washington, D.C. 20460. In addition, copies of the comment summary may be obtained upon written request from the EPA Public Information Center (PM-215), 401 M Street, SW., Washington, D.C. 20460 (specify "Public Comment Summary: Section 111(d) Regulations").

(1) *Definitions and basic concepts.* The term "emission limitation" as defined in proposed § 60.21(e) has apparently caused some confusion. As used in the proposal, the term was not intended to mean a legally enforceable national emission standard as some comments suggested. Indeed, the term was chosen in an attempt to avoid such confusion. EPA's rationale for using the emission limitation concept is presented below in the discussion of the basis for approval or disapproval of State plans. However, to emphasize that a legally enforceable standard is not intended, the term "emission limitation" has been replaced with the term "emission guideline" [see § 60.21(e)]. In addition, proposed § 60.27 (concerning publication of guideline documents and so forth) has been moved forward in the regulations (becoming § 60.22) to emphasize that publication of a final guideline document is the "trigger" for State action under subsequent sections of Subpart B [see § 60.23(a)].

Many commentators apparently confused the degree of control to be reflected in EPA's emission guidelines under section 111(d) with that to be required by corresponding standards of performance for new sources under section 111(b). Although the general principle (application of best adequately demonstrated control technology, considering costs) will be the same in both cases, the degrees of control represented by EPA's emission guidelines will ordinarily be less stringent than those required by standards of performance for new sources because the costs of controlling existing facilities will ordinarily be greater than those for control of new sources. In addition, the regulations have been amended to make clear that the Administrator will specify different emission guidelines for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, and similar factors make subcategorization approprate [§ 60.22(b)(5)]. Thus, while there may be only one standard of performance for new sources of designated pollutants, there may be several emission guidelines specified for designated facilities based on plant configuration, size, and other factors peculiar to existing facilities.

Some comments evidenced confusion regarding the relationship of affected facilities and designated facilities. An affected facility, as defined in § 60.2(e), is a new or modified facility subject to a standard of performance for new stationary sources. An existing facility [§ 60.2(aa)] is a facility of the same type as an affected facility, but one the construction of which commenced before the date of proposal of applicable standards of performance. A designated facility [§ 60.21(d)] is an existing facility which emits a designated pollutant.

A few industry comments argued that the proposed regulations would permit EPA to circumvent the legal and technical safeguards required under sections 108, 109, and 110 of the Act, sections which the commentators characterized as the basic statutory process for control of existing facilities. Congress clearly intended control of existing facilities under sections other than 108, 109, and 110. Sections 112 and 303 as well as 111(d) itself provide for control of existing facilities. Moreover, action under section 111(d) is subject to a number of significant safeguards: (1) Before acting under section 111(d) the Administrator must have found under section 111(b) that a source category may significantly contribute to air pollution which causes or contributes to the endangerment of public health or welfare, and this finding must be technically supportable; (2) EPA's emission guidelines will be developed in consultation with industrial groups and the National Air Pollution Control Techniques Advisory Committee, and they will be subject to public comment before they are adopted; (3) emission standards and other plan provisions must be subjected to public hearings prior to adoption; (4) relief is available under § 60.24(f) or § 60.27(e)(2) where application of emission standards to particular sources would be unreasonable; and (5) judicial review of the Administrator's action in approving or promulgating plans (or portions thereof) is available under section 307 of the Act.

A number of commentators suggested that special provisions for plans submitted under section 111(d) are unnecesssary since existing facilities are covered by State implementation plans (SIPs) approved or promulgated under section 110 of the Act. By its own terms, however, section 111(d) requires the Administrator to prescribe regulations for section 111(d) plans. In addition, the pollutants to which section 111(d) applies (i.e., designated pollutants) are not controlled as such under the SIPs. Under section 110, the SIPs only regulate criteria pollutants; i.e., those for which national ambient air quality standards have been established under section 109 of the Act. By definition, designated pollutants are non-criteria pollutants [§ 60.21(a)]. Although some designated pollutants may occur in particulate as well as gaseous forms and thus may be controlled to some degree under SIP provisions requiring control of particulate matter, specific rather than incidental control of such pollutants is required by section 111(d). For these reasons, separate regulations are necessary to establish the framework for specific control of designated pollutants under section 111(d).

Comments of a similar nature argued that if there are demonstrable health and welfare effects from designated pollutants, either air quality criteria should be established and SIPs submitted under sections 108–110 of the Act, or the provisions of section 112 of the Act should be applied. Section 111(d) of the Act was specifically designed to require control of pollutants which are not presently considered "hazardous" within the meaning of section 112 and for which ambient air quality standards have not been promulgated. Health and welfare effects from these designated pollutants often cannot be quantified or are of such a nature that the effects are cumulative and not associated with any particular

21 **Title 40—Protection of Environment**

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 437-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

State Plans for the Control of Certain Pollutants From Existing Facilities

On October 7, 1974 (39 FR 36102), EPA proposed to add a new Subpart B to Part 60 to establish procedures and requirements for submittal of State plans for control of certain pollutants from existing facilities under section 111(d) of the Clean Air Act, as amended (42 U.S.C. 1857c-6(d)). Interested persons participated in the rulemaking by sending comments to EPA. A total of 45 comment letters was received, 19 of which came from industry, 16 from State and local agencies, 5 from Federal agencies, and 5 from other interested parties. All comments have been carefully considered, and the proposed regulations have been reassessed. A number of changes suggested in comments have been made, as well as changes developed within the Agency.

One significant change, discussed more fully below, is that different procedures and criteria will apply to submittal and approval of State plans where the Administrator determines that a particular pollutant may cause or contribute to the endangerment of public welfare, but that adverse effects on public health have not been demonstrated. Such a determination might be made, for example, in the case of a pollutant that damages crops but has no known adverse effect on public health. This change is intended to allow States more flexibility in establishing plans for the control of such pollutants than is provided for plans involving pollutants that may affect public health.

Most other changes were of a relatively minor nature and, aside from the change just mentioned, the basic concept of the regulations is unchanged. A number of provisions have been reworded to resolve ambiguities or otherwise clarify their meaning, and some were combined or otherwise reorganized to clarify and simplify the overall organization of Subpart B.

Background

When Congress enacted the Clean Air Amendments of 1970, it addressed three general categories of pollutants emitted from stationary sources. See Senate Report No. 91-1196, 91st Cong., 2d Sess. 18-19 (1970). The first category consists of pollutants (often referred to as "criteria pollutants") for which air quality criteria and national ambient air quality standards are established under sections 108 and 109 of the Act. Under the 1970 amendments, criteria pollutants are controlled by State implementation plans (SIP's) approved or promulgated under section 110 and, in some cases, by standards of performance for new sources established under section 111. The second category consists of pollutants listed as hazardous pollutants under section 112 and controlled under that section.

The third category consists of pollutants that are (or may be) harmful to public health or welfare but are not or cannot be controlled under sections 108-110 or 112. Section 111(d) requires control of existing sources of such pollutants whenever standards of performance (for those pollutants) are established under section 111(b) for new sources of the same type.

In determining which statutory approach is appropriate for regulation of a particular pollutant, EPA considers the nature and severity of the pollutant's effects on public health or welfare, the number and nature of its sources, and similar factors prescribed by the Act. Where a choice of approaches is presented, the regulatory advantages and disadvantages of the various options are also considered. As indicated above, section 111(d) requires control of existing sources of a pollutant if a standard of performance is established for new sources under section 111(b) and the pollutant is not controlled under sections 108-110 or 112. In general, this means that control under section 111(d) is appropriate when the pollutant may cause or contribute to endangerment of public health or welfare but is not known to be "hazardous" within the meaning of section 112 and is not controlled under sections 108-110 because, for example, it is not emitted from "numerous or diverse" sources as required by section 108.

For ease of reference, pollutants to which section 111(d) applies as a result of the establishment of standards of performance for new sources are defined in § 60.21(a) of the new Subpart B as "designated pollutants." Existing facilities which emit designated pollutants and which would be subject to the standards of performance for those pollutants, if new, are defined in § 60.21(b) as "designated facilities."

As indicated previously, the proposed regulations have been revised to allow States more flexibility in establishing plans where the Administrator determines that a designated pollutant may cause or contribute to endangerment of public welfare, but that adverse effects on public health have not been demonstrated. For convenience of discussion, designated pollutants for which the Administrator makes such a determination are referred to in this preamble as "welfare-related pollutants" (i.e., those requiring control solely because of their effects on public welfare). All other designated pollutants are referred to as "health-related pollutants."

To date, standards of performance have been established under section 111 of the Act for two designated pollutants—fluorides emitted from five categories of sources in the phosphate fertilizer industry (40 FR 33152, August 6, 1975) and sulfuric acid mist emitted from sulfuric acid production units (36 FR 24877, December 23, 1971). In addition, standards of performance have been proposed for fluorides emitted from primary aluminum plants (39 FR 37730, October 23, 1974), and final action on these standards will occur shortly. EPA will publish draft guideline documents (see next section) for these pollutants in the near future. Although a final decision has not been made, it is expected that sulfuric acid mist will be determined to be a health-related pollutant and that fluorides will be determined to be welfare-related.

Summary of Regulations

Subpart B provides that after a standard of performance applicable to emissions of a designated pollutant from new sources is promulgated, the Administrator will publish guideline documents containing information pertinent to control of the same pollutant from designated (i.e., existing) facilities [§ 60.22(a)]. The guideline documents will include "emission guidelines" (discussed below) and compliance times based on factors specified in § 60.22(b)(5) and will be made available for public comment in draft form before being published in final form. For health-related pollutants, the Administrator will concurrently propose and subsequently promulgate the emission guidelines and compliance times referred to above [§ 60.22(c)]. For welfare-related pollutants, emission guidelines and compliance times will appear only in the applicable guideline documents [§ 60.22(d)(1)].

The Administrator's determination that a designated pollutant is heath-related, welfare-related, or both and the rationale for the determination will be provided in the draft guideline document for that pollutant. In making this determination, the Administrator will consider such factors as: (1) Known and suspected effects of the pollutant on public health and welfare; (2) potential ambient concentrations of the pollutant; (3) generation of any secondary pollutants for which the designated pollutant may be a precursor; (4) any synergistic effect with other pollutants; and (5) potential effects from accumulation in the environment (e.g., soil, water and food chains). After consideration of comments and other information a final determination and rationale will be published in the final guidelines document.

For both health-related and welfare-related pollutants, emission guidelines will reflect the degree of control attainable with the application of the best systems of emission reduction which (considering the cost of such reduction) have been adequately demonstrated for designated facilities [§ 60.21(e)]. As discussed more fully below, the degree of control reflected in EPA's emission guidelines will take into account the costs of retrofitting existing facilities and thus will probably be less stringent than corresponding standards of performance for new sources.

After publication of a final guideline document for a designated pollutant, the States will have nine months to develop

Date of Test _____

Span Gas Concentration _____ ppm

Analyzer Span Setting _____ ppm

Upscale
1. _____ seconds
2. _____ seconds
3. _____ seconds

Average upscale response _____ seconds

Downscale
1. _____ seconds
2. _____ seconds
3. _____ seconds

Average downscale response _____ seconds

System average response time (slower time) = _____ seconds

% deviation from slower system average response = $\frac{\text{average upscale minus average downscale}}{\text{slower time}} \times 100\%$

= _____.

Figure 3-3. Response

[FR Doc.75-26565 Filed 10-3-75;8:45 am]

19 Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 442-3]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCE

Delegation of Authority to State of New York

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of New York on August 6, 1975, EPA is today amending 40 CFR 60.4, Address, to reflect this delegation. A Notice announcing this delegation is published elsewhere in today's FEDERAL REGISTER. The amended § 60.4, which adds the address of the New York State Department of Environmental Conservation, to which reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on August 6, 1975, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations. This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended. 42 U.S.C. 1857c-6.

Dated: October 4, 1975.

STANLEY W LEGRO,
Assistant Administrator for Enforcement.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (HH) to read as follows:

§ 60.4 Address.

* * * * * *

(b) * * *

(HH)—New York: New York State Department of Environmental Conservation, 50 Wolf Road, New York 12233, attention: Division of Air Resources.

[FR Doc.75-27582 Filed 10-14-75;8:45 am]

20 [449-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCE

Delegation of Authority to State of Colorado

Pursuant to the delegation of authority for the standards of performance for eleven categories of new stationary sources (NSPS) to the State of Colorado on August 27, 1975, EPA is today amending 40 CFR 60.4, Address, to reflect this delegation. A Notice announcing this delegation is published today in the FEDERAL REGISTER. The amended § 60.4, which adds the address of the Colorado Air Pollution Control Division to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on August 27, 1975, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended, 42 U.S.C. 1857c-6.

Dated: October 22, 1975.

STANLEY W LEGRO,
Assistant Administrator for Enforcement.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (G) to read as follows:

§ 60.4 Address.

* * * * * *

(b) * * *

(G)—*State of Colorado*, Colorado Air Pollution Control Division, 4210 East 11th Avenue, Denver, Colorado 80220.

* * * * * *

[FR Doc.75-29234 Filed 10-30-75;8:45 am]

Data Set No.	Time Begin	Time End	Date	Zero Reading	Zero Drift (ΔZero)	Span Reading	Span Drift (ΔSpan)	Calibration Drift (ΔSpan-ΔZero)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								

Zero Drift = [Mean Zero Drift* _____ + CI (Zero) _____] = _____.
Calibration Drift = [Mean Span Drift* _____ + CI (Span _____] = _____.
*Absolute Value.

Figure 3-1. Zero and Calibration Drift (2 Hour).

Date and Time	Zero Reading	Zero Drift (ΔZero)	Span Reading (After zero adjustment)	Calibration Drift (ΔSpan)

Zero Drift = [Mean Zero Drift* _____ + C.I. (Zero) _____]

= _____.

Calibration Drift = [Mean Span Drift* _____ + C.I. (Span) _____]

= _____.

* Absolute value

Figure 3-2. Zero and Calibration Drift (24-hour)

ambient level. Quite often, health and welfare problems caused by such pollutants are highly localized and thus an extensive procedure, such as the SIPs require, is not justified. As previously indicated, Congress specifically recognized the need for control of a third category of pollutants; it also recognized that as additional information becomes available, these pollutants might later be reclassified as hazardous or criteria pollutants.

Other commentators reasoned that since designated pollutants are defined as non-criteria and non-hazardous pollutants, only harmless substances would fall within this category. These commentators argued that the Administrator should establish that a pollutant has adverse effects on public health or welfare before it could be regulated under section 111(d). Before acting under section 111(d), however, the Administrator must establish a standard of performance under section 111(b). In so doing, the Administrator must find under section 111(b) that the source category covered by such standards may contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare.

(2) *Basis for approval or disapproval of State plans.* A number of industry comments questioned EPA's authority to require, as a basis for approval of State plans, that the States establish emission standards that (except in cases of economic hardship) are equivalent to or more stringent than EPA's emission guidelines. In general, these comments argued that EPA has authority only to prescribe procedural requirements for adoption and submittal of State plans, leaving the States free to establish emission standards on any basis they deem necessary or appropriate. Most State comments expressed no objection to EPA's interpretation on this point, and a few explicitly endorsed it.

After careful consideration of these comments, EPA continues to believe, for reasons summarized below, that its interpretation of section 111(d) is legally correct. Moreover, EPA believes that its interpretation is essential to the effective implementation of section 111(d), particularly where health-related pollutants are involved. As discussed more fully below, however, EPA has decided that it is appropriate to allow States somewhat more flexibility in establishing plans for the control of welfare-related pollutants and has revised the proposed regulations accordingly.

Although section 111(d) does not specify explicit criteria for approval or disapproval of State plans, the Administrator must disapprove plans that are not "satisfactory" [Section 111(d)(2)(A)]. Appropriate criteria must therefore be inferred from the language and context of section 111(d) and from its legislative history. It seems clear, for example, that the Administrator must disapprove plans not adopted and submitted in accordance with the procedural requirements he prescribes under section 111(d), and none of the commentators questioned this concept. The principal questions, therefore, are whether Congress intended that the Administrator base approvals and disapprovals on substantive as well as procedural criteria and, if so, on what types of substantive criteria.

A brief summary of the legislative history of section 111(d) will facilitate discussion of these questions. Section 111(d) was enacted as part of the Clean Air Amendments of 1970. No comparable provision appeared in the House bill. The Senate bill, however, contained a section 114 that would have required the establishment of national emission standards for "selected air pollution agents." Although the term "selected air pollution agent" did not include pollutants that might affect public welfare [which are subject to control under section 111(d)], its definition otherwise corresponded to the description of pollutants to be controlled under section 111(d). Section 114 of the Senate bill was rewritten in conference to become section 111(d). Although the Senate report and debates include references to the intent of section 114, neither the conference report nor subsequent debates include any discussion of section 111(d) as finally enacted. In the absence of such discussion, EPA believes inferences concerning the legislative intent of section 111(d) may be drawn from the general purpose of section 114 of the Senate bill and from the manner in which it was rewritten in conference.

After a careful examination of section 111(d), its statutory context, and its legislative history, EPA believes the following conclusions may be drawn:

(1) As appears from the Senate report and debates, section 114 of the Senate bill was designed to address a specific problem. That problem was how to reduce emissions of pollutants which are (or may be) harmful to health but which, on the basis of information likely to be available in the near term, cannot be controlled under other sections of the Act as criteria pollutants or as hazardous pollutants. (It was made clear that such pollutants might be controlled as criteria or hazardous pollutants as more definitive information became available.) The approach taken in section 114 of the Senate bill was to require national emission standards designed to assure that emissions of such pollutants would not endanger health.

(2) The Committee of Conference chose to rewrite the Senate provision as part of section 111, which in effect requires maximum feasible control of pollutants from new stationary sources through technology-based standards (as opposed to standards designed to assure protection of health or welfare or both). For reasons summarized below, EPA believes this choice reflected a decision in conference that a similar approach (making allowances for the costs of controlling existing sources) was appropriate for the pollutants to be controlled under section 111(d).

(3) As reflected in the Senate report and debates, the pollutants to be controlled under section 114 of the Senate bill were considered a category distinct from the pollutants for which criteria documents had been written or might soon be written. In part, these pollutants differed from the criteria pollutants in that much less information was available concerning their effects on public health and welfare. For that reason, it would have been difficult—if not impossible—to prescribe legally defensible standards designed to protect public health or welfare for these pollutants until more definitive information became available. Yet the pollutants, by definition, were those which (although not criteria pollutants and not known to be hazardous) had or might be expected to have adverse effects on health.

(4) Under the circumstances, EPA believes, the conferees decided (a) that control of such pollutants on some basis was necessary; (b) that, given the relative lack of information on their health and welfare effects, a technology-based approach (similar to that for new sources) would be more feasible than one involving an attempt to set standards tied specifically to protection of health; and (c) that the technology-based approach (making allowances for the costs of controlling existing sources) was a reasonable means of attacking the problem until more definitive information became known, particularly because the States would be free under section 116 of the Act to adopt more stringent standardse if they believed additional control was desirable. In short, EPA believes the conferees chose to rewrite section 114 as part of section 111 largely because they intended the technology-based approach of that section to extend (making allowances for the costs of controlling existing sources) to action under section 111(d). In this view, it was unnecessary (although it might have been desirable) to specify explicit substantive criteria in section 111(d) because the intent to require a technology-based approach could be inferred from placement of the provision in section 111.

Related considerations support this interpretation of section 111(d). For example, section 111(d) requires the Administrator to prescribe a plan for a State that fails to submit a satisfactory plan. It is obvious that he could only prescribe standards on some substantive basis. The references to section 110 of the Act suggest that (as in section 110) he was intended to do generally what the States in such cases should have done, which in turn suggests that (as in section 110) Congress intended the States to prescribe standards on some substantive basis. Thus, it seems clear that some substantive criterion was intended to govern not only the Administrator's promulgation of standards but also his review of State plans.

Still other considerations support EPA's interpretation of section 111(d). Even a cursory examination of the legislative history of the 1970 amendments reveals that Congress was dissatisfied with air pollution control efforts at all levels

of government and was convinced that relatively drastic measures were necessary to protect public health and welfare. The result was a series of far-reaching amendments which, coupled with virtually unprecedented statutory deadlines, required EPA and the States to take swift and aggressive action. Although Congress left initial responsibility with the States for control of criteria pollutants under section 110, it set tough minimum criteria for such action and required Federal assumption of responsibility where State action was inadequate. It also required direct Federal action for control of new stationary sources, hazardous pollutants, and mobile sources. Finally, in an extraordinary departure from its practice of delegating rulemaking authority to administrative agencies (a departure intented to force the pace of pollution control efforts in the automobile industry), Congress itself enacted what amounted to statutory emission standards for the principal automotive pollutants.

Against this background of Congressional firmness, the overriding purpose of which was to protect public health and welfare, it would make no sense to interpret section 111(d) as requiring the Administrator to base approval or disapproval of State plans solely on procedural criteria. Under that interpretation, States could set extremely lenient standards—even standards permitting greatly increased emissions—so long as EPA's procedural requirements were met Given that the pollutants in question are (or may be) harmful to public health and welfare, and that section 111(d) is the only provision of the Act requiring their control, it is difficult to believe that Congress meant to leave such a gaping loophole in a statutory scheme otherwise designed to force meaningful action.

Some of the comments on the proposed regulations assume that the States were intended to set emission standards based directly on protection of public health and welfare. EPA believes this view is consistent with its own view that the Administrator was intended to base approval or disapproval of State plans on substantive as well as procedural criteria but believes Congress intended a technology-based approach rather than one based directly on protection of health and welfare. The principal factors leading EPA to this conclusion are summarized above. Another is that if Congress had intended an approach based directly on protection of health and welfare, it could have rewritten section 114 of the Senate bill as part of section 110, which epitomizes that approach, rather than as part of section 111. Indeed, with relatively minor changes in language, Congress could simply have retained section 114 as a separate section requiring action based directly on protection of health and welfare.

Still another factor is that asking each of the States, many of which had limited resources and expertise in air pollution control, to set standards protective of health and welfare in the absence of adequate information would have made even less sense than requiring the Administrator to do so with the various resources at his command. Requiring a technology-based approach, on the other hand, would not only shift the criteria for decision-making to more solid ground (the availability and costs of control technology) but would also take advantage of the information and expertise available to EPA from its assessment of techniques for the control of the same pollutants from the same types of sources under section 111(b), as well as its power to compel submission of information about such techniques under section 114 of the Act (42 U.S.C. 1857c-9). Indeed, section 114 was made specifically applicable for the purpose (among others) of assisting in the development of State plans under section 111(d). For all of these reasons, EPA believes Congress intended a technology-based approach rather than one based directly on protection of health and welfare.

Some of the comments argued that EPA's emission guidelines under section 111(d) will, in effect, be national emission standards for existing sources, a concept they argue was rejected in section 111(d). In general, the comments rely on the fact that although section 114 of the Senate bill specifically provided for national emission standards, section 111(d) calls for establishment of emission standards by States. EPA believes that the rewriting of section 114 in conference is consistent with the establishment of national criteria by which to judge the adequacy of State plans, and that the approach taken in section 111(d) may be viewed as largely the result of two decisions: (1) To adopt a technology-based approach similar to that for new sources; and (2) to give States a greater role than was provided in section 114. Thus, States will have primary responsibility for developing and enforcing control plans under section 111(d); under section 114, they would only have been invited to seek a delegation of authority to enforce Federally developed standards. Under EPA's interpretation of section 111(d), States will also have authority to grant variances in cases of economic hardship; under section 114, only the Administrator would have had authority to grant such relief. As with section 110, assigning primary responsibility to the States in these areas is perfectly consistent with review of their plans on some substantive basis. If there is to be substantive review, there must be criteria for the review, and EPA believes it is desirable (if not legally required) that the criteria be made known in advance to the States, to industry, and to the general public. The emission guidelines, each of which will be subjected to public comment before final adoption, will serve this function.

In any event, whether or not Congress "rejected" the concept of national emission standards for existing sources, EPA's emission guidelines will not have the purpose or effect of national emission standards. As emphasized elsewhere in this preamble, they will not be requirements enforceable against any source. Like the national ambient air quality standards prescribed under section 109 and the items set forth in section 110(a)(2)(A)-(H), they will only be criteria for judging the adequacy of State plans.

Moreover, it is inaccurate to argue (as did one comment) that, because EPA's emission guidelines will reflect best available technology considering cost, States will be unable to set more stringent standards. EPA's emission guidelines will reflect its judgment of the degree of control that can be attained by various classes of existing sources without unreasonable costs. Particular sources within a class may be able to achieve greater control without unreasonable costs. Moreover, States that believe additional control is necessary or desirable will be free under section 116 of the Act to require more expensive controls, which might have the effect of closing otherwise marginal facilities, or to ban particular categories of sources outright. Section 60.24(g) has been added to clarify this point. On the other hand, States will be free to set more lenient standards, subject to EPA review, as provided in §§ 60.24(d) and (f) in the case of welfare-related pollutants and in cases of economic hardship.

Finally, as discussed elsewhere in this preamble, EPA's emission guidelines will reflect subcategorization within source categories where appropriate, taking into account differences in sizes and types of facilities and similar con- §§ 60.24 (d) and (f) in the case of wel- siderations, including differences in control costs that may be involved for sources located in different parts of the country. Thus, EPA's emission guidelines will in effect be tailored to what is reasonably achievable by particular classes of existing sources, and States will be free to vary from the levels of control represented by the emission guidelines in the ways mentioned above. In most if not all cases, the result is likely to be substantial variation in the degree of control required for particular sources, rather than identical standards for all sources.

In summary, EPA believes section 111(d) is a hybrid provision, intended to combine primary State responsibility for plan development and enforcement (as in section 110) with the technology-based approach (making allowances for the costs of controlling existing sources) taken in section 111 generally. As indicated above, EPA believes its interpretation of section 111(d) is legally correct in view of the language, statutory context and legislative history of the provision.

Even assuming some other interpretation were permissible, however, EPA believes its interpretation is essential to the effective implementation of section 111(d), particularly where health-related pollutants are involved. Most of the reasons for this conclusion are discussed above, but it may be useful to summarize them here. Given the relative lack of information concerning the effects of designated pollutants on public health and welfare, it would be

difficult—if not impossible—for the States or EPA to prescribe legally defensible standards based directly on protection of health and welfare. By contrast, a technology-based approach takes advantage of the information and expertise available to EPA from its assessment of techniques for the control of the same pollutants from the same types of sources under section 111(b), as well as EPA's power to compel submission of information about such techniques under section 114 of the Act. Given the variety of circumstances that may be encountered in controlling existing as opposed to new sources, it makes sense to have the States develop plans based on technical information provided by EPA and make judgments, subject to EPA review, concerning the extent to which less stringent requirements are appropriate. Finally, EPA review of such plans for their substantive adequacy is essential (particularly for health-related pollutants) to assure that meaningful controls will be imposed. For these reasons, given a choice of permissible interpretations of section 111(d), EPA would choose the interpretation on which Subpart B is based on the ground that it is essential to the effective implementation of the provision, particularly where health-related pollutants are involved.

As indicated previously, however, EPA has decided that it is appropriate to allow the States more flexibility in establishing plans for the control of welfare-related pollutants than is provided for plans involving health-related pollutants. Accordingly, the proposed regulations have been revised to provide that States may balance the emission guidelines, compliance times and other information in EPA's guideline documents against other factors in establishing emission standards, compliance schedules, and variances for welfare-related pollutants, provided that appropriate consideration is given to the information presented in the guideline documents and at public hearings, and that all other requirements of Subpart B are met [§ 60.24(d)]. Where sources of pollutants that cause only adverse effects to crops are located in nonagricultural areas, for example, or where residents of a local community depend on an economically marginal plant for their livelihood, such factors could be taken into account. Consistent with section 116 of the Act, of course, States will remain free to adopt requirements as stringent as (or more stringent than) the corresponding emission guidelines and compliance times specified in EPA's guideline documents if they wish [see § 60.24(g)].

A number of factors influenced EPA's decision to allow States more flexibility in establishing plans for control of welfare-related pollutants than is provided for plans involving health-related pollutants. The dominant factor, of course, is that effects on public health would not be expected to occur in such cases, even if State plans required no greater controls than are presently in effect. In a sense, allowing the States greater latitude in such cases simply reflects EPA's view (stated in the preamble to the proposed regulations) that requiring maximum feasible control of designated pollutants may be unreasonable in some situations. Although pollutants that cause only damage to vegetation, for example, are subject to control under section 111(d), few would argue that requiring maximum feasible control is as important for such pollutants as it is for pollutants that endanger public health.

This fundamental distinction—between effects on public health and effects on public welfare—is reflected in section 110 of the Act, which requires attainment of national air quality standards that protect public health within a certain time (regardless of economic and social consequences) but requires attainment of national standards that protect public welfare only within "a reasonable time." The significance of this distinction is reflected in the legislative history of section 110; and the legislative history of section 111(d), although inconclusive, suggests that its primary purpose was to require control of pollutants that endanger public health. For these reasons, EPA believes it is both permissible under section 111(d) and appropriate as a matter of policy to approve State plans requiring less than maximum feasible control of welfare-related pollutants where the States wish to take into account considerations other than technology and cost.

On the other hand, EPA believes section 111(d) requires maximum feasible control of welfare-related pollutants in the absence of such considerations and will disapprove plans that require less stringent control without some reasoned explanation. For similar reasons, EPA will promulgate plans requiring maximum feasible control if States fail to submit satisfactory plans for welfare-related pollutants [§ 60.27(e)(1).] Under § 60.27(e)(2), however, relief will still be available for particular sources where economic hardship can be shown.

(3) *Variances.* One comment asserted that neither the letter nor the intent of section 111 allows variances from plan requirements based on application of best adequately demonstrated control systems. Although section 111(d) does not explicitly provide for variances, it does require consideration of the cost of applying standards to existing facilities. Such a consideration is inherently different than for new sources, because controls cannot be included in the design of an existing facility and because physical limitations may make installation of particular control systems impossible or unreasonably expensive in some cases. For these reasons, EPA believes the provision [§ 60.24(f)] allowing States to grant relief in cases of economic hardship (where health-related pollutants are involved) is permissible under section 111(d). For the same reasons, language has been included in § 60.24(d) to make clear that variances are also permissible where welfare-related pollutants are involved, although the flexibility provided by that provision may make variances unnecessary.

Several commentators urged that proposed § 60.23(e) [now § 60.24(f)] be amended to indicate that States are not required to consider applications for variances if they do not feel it appropriate to do so. The commentators contended that the proposed wording would invite applications for variances, would allow sources to delay compliance by submitting such applications, might conflict with existing State laws, and would probably impose significant burdens on State and local agencies. In addition, there is some question whether the mandatory review provision as proposed would be consistent with section 116 of the Act, which makes clear that States are free to adopt and enforce standards more stringent than Federal standards. Accordingly, the proposed wording has been amended to permit, but not require, State review of facilities for the purpose of applying less stringent standards. To give the States more flexibility, § 60.24(f) has also been amended to permit variances for particular classes of sources as well as for particular sources.

Other comments requested that EPA make clear whether proposed § 60.23(e) [now § 60.24(f)] would allow permanent variances or whether EPA intends ultimate compliance with the emission standards that would apply in the absence of variances. Section 60.24(f) is intended to utilize existing State variance procedures as much as possible. Thus it is up to the States to decide whether less stringent standards are to be applied permanently or whether ultimate compliance will be required.

Another commentator suggested that compliance with or satisfactory progress toward compliance with an existing State emission standard should be a sufficient reason for applying a less stringent standard under § 60.24(f). Such compliance is not necessarily sufficient because existing standards have not always been developed with the intention of requiring maximum feasible control. As indicated in the preamble to the proposed regulations, however, if an existing State emission standard is relatively close to the degree of control that would otherwise be required, and the cost of additional control would be relatively great, there may be justification to apply a less stringent standard under § 60.24(f).

One thoughtful comment suggested that consideration of variances under Subpart B could in effect undermine related SIP requirements; e.g., where designated pollutants occur in particulate forms and are thus controlled to some extent under SIP requirements applicable to particulate matter. Nothing in section 111(d) or Subpart B, however, will preempt SIP requirements. In the event of a conflict, protection of health and welfare under section 110 must control.

(4) *Public hearing requirement.* Based on comments that the requirement for a public hearing on the plan in each AQCR

containing a designated facility is too burdensome, the proposed regulation has been amended to require only one hearing per State per plan. While the Agency advocates public participation in environmental rulemaking, it also recognizes the expense and effort involved in holding multiple hearings. States are urged to hold as many hearings as practicable to assure adequate opportunity for public participation. The hearing requirements have also been amended to provide that a public hearing is not required in those States which have an existing emission standard that was adopted after a public hearing and is at least as stringent as the corresponding EPA emission guidelines, and to permit approval of State notice and hearing procedures different than those specified in Subpart B in some cases.

(5) *Compliance schedules.* The proposed regulation required that all compliance schedules be submitted with the plan. Several commentators suggested that this requirement would not allow sufficient time for negotiation of schedules and could cause duplicative work if the emission standards were not approved. For this reason a new § 60.24 (e) (2) has been added to allow submission of compliance schedules after plan submission but no later than the date of the first semiannual report required by § 60.25(e).

(6) *Existing regulations.* Several comments dealt with States which have existing emission standards for designated pollutants. One commentator urged that such States be exempted from the requirements of adopting and submitting plans. However, the Act requires EPA to evaluate both the adequacy of a State's emission standards and the procedural aspects of the plan. Thus, States with existing regulations must submit plans.

Another commentator suggested that the Administrator should approve existing emission standards which, because they are established on a different basis (e.g., concentration standards vs. process-weight-rate type standards), are more stringent than the corresponding EPA emission guideline for some facilities and less stringent for others. The Agency cannot grant blanket approval for such emission standards; however, the Administrator may approve that part of an emission standard which is equal to or more stringent than the EPA emission guideline and disapprove that portion which is less stringent. Also, the less stringent portions may be approvable in some cases under § 60.24 (d) or (f). Finally, subcategorization by size of source under § 60.22(b)(5) will probably limit the number of cases in which this situation will arise.

Other commentators apparently assumed that some regulations for designated pollutants were approved in the State implementation plans (SIPs). Although some States may have submitted regulations limiting emissions of designated pollutants with the SIPs, such regulations were not considered in the approval or disapproval of those plans and are not considered part of approved plans because, under section 110, SIPs, apply only to criteria pollutants.

(7) *Emission inventory data and reports.* Section 60.24 of the proposed regulations [now § 60.25] required emission inventory data to be submitted on data forms which the Administrator was to specify in the future. It was expected that a computerized subsystem to the National Emission Data System (NEDS) would be available that would accommodate emission inventory information on the designated pollutants. However, since this subsystem and concomitant data form will probably not be developed and approved in time for plan development, the designated pollutant information called for will not be required in computerized data format. Instead, the States will be permitted to submit this information in a non-computerized format as outlined in a new Appendix D along with the basic facility information on NEDS forms (OMB #158–R0095) according to procedures in APTD 1135, "Guide for Compiling a Comprehensive Emission Inventory" available from the Air Pollution Technical Information Center, Environmental Protection Agency, Research Triangle Park, North Carolina 27711. In addition, § 60.25(f)(5) has been amended to require submission of additional information with the semiannual reports in order to provide a better tracking mechanism for emission inventory and compliance monitoring purposes.

(8) *Timing.* Proposed § 60.27(a) required proposal of emission guidelines for designated pollutants simultaneously with proposal of corresponding standards of performance for new (affected) facilities. This section, redesignated § 60.22, has been amended to require proposal (or publication for public comment) of an emission guideline after promulgation of the corresponding standard of performance. Two written comments and several informal comments from industrial representatives indicated that more time was needed to evaluate a standard of performance and the corresponding emission guideline than would be allowed by simultaneous proposal and promulgation. Also, by proposing (or publishing) an emission guideline after promulgation of the corresponding standard of performance, the Agency can benefit from the comments on the standard of performance in developing the emission guideline.

Proposed § 60.27(a) required proposal of sulfuric acid mist emission guidelines within 30 days after promulgation of Subpart B. This provision was included as an exception to the proposed general rule (requiring simultaneous proposal of emission guidelines and standards of performance) because it was impossible to propose the acid mist emission guideline simultaneously with the corresponding standard of performance, which had been promulgated previously. The change in the general rule, discussed above, makes the proposed exception unnecessary, so it has been deleted. As previously stated, the Agency intends to establish emission guidelines for sulfuric acid mist [and for fluorides, for which new source standards were promulgated (40 FR 33152) after proposal of Subpart B] as soon as possible.

(9) *Miscellaneous.* Several commentators argued that the nine months provided for development of State plans after promulgation of an emission guideline by EPA would be insufficient. In most cases, much of the work involved in plan development, such as emission inventories, can be begun when an emission guideline is proposed (or published for comment) by EPA; thus, several additional months will be gained. Extensive control strategies are not required, and after the first plan is submitted, submitted, subsequent plans will mainly consist of adopted emission standards. Section 111(d) plans will be much less complex than the SIPs, and Congress provided only nine months for SIP development. Also, States may already have approvable procedures and legal authority [see §§ 60.25(d) and 60.26(b)], and the number of designated facilities per State should be few. For these reasons, the nine-month provision has been retained.

Some comments recommended that the requirements for adoption and submittal of section 111(d) plans appear in 40 CFR Part 51 or in some part of 40 CFR other than Part 60, to allow differentiation among such requirements, emission guidelines, new source standards and plans promulgated by EPA. The Agency believes that the section 111(d) requirements neither warrant a separate part nor should appear in Part 51, since Part 51 concerns control under section 110 of the Act. For clarity, however, subpart B of Part 60 will contain the requirements for adoption and submittal of section 111(d) plans; Subpart C of Part 60 will contain emission guidelines and times for compliance promulgated under § 60.22 (c); and a new Part 62 will be used for approval or disapproval of section 111(d) and for plans (or portions thereof) promulgated by EPA where State plans are disapproved in whole or in part.

Two comments suggested that the plans should specify test methods and procedures to be used in demonstrating compliance with the emission standards. Only when such procedures and methods are known can the stringency of the emission standard be determined. Accordingly, this change has been included in § 60.24(b).

A new § 60.29 has been added to make clear that the Administrator may revise plan provisions he has promulgated under § 60.27(d), and § 60.27(e) has been revised to make clear that he will consider applications for variances from emission standards promulgated by EPA.

Effective Date. These regulations become effective on December 17, 1975.

(Sections 111, 114, and 301 of the Clean Air Act, as amended by sec. 4(a) of Pub. L. 91-604, 84 Stat. 1678, and by sec. 15(c)(2) of Pub. L. 91-604, 84 Stat. 1713 (42 U.S.C. 1857c-6, and 1857c-9, 1857g).

Dated: November 5, 1975.

JOHN QUARLES,
Acting Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. The table of sections for Part 60 is amended by adding a list of sections for Subpart B and by adding Appendix D to the list of appendixes as follows:

* * * * *

Subpart B—Adoption and Submittal of State Plans for Designated Facilities

Sec
60.20 Applicability.
60.21 Definitions.
60.22 Publication of guideline documents, emission guidelines, and final compliance times.
60.23 Adoption and submittal of State plans; public hearings.
60.24 Emission standards and compliance schedules.
60.25 Emission inventories, source surveillance, reports.
60.26 Legal authority.
60.27 Actions by the Administrator.
60.28 Plan revisions by the State.
60.29 Plan revisions by the Administrator.

* * * * *

APPENDIX D—REQUIRED EMISSION INVENTORY INFORMATION

2. The authority citation at the end of the table of sections for Part 60 is revised to read as follows:

AUTHORITY: Secs. 111 and 114 of the Clean Air Act, as amended by sec. 4(a) of Pub. L. 91-604, 84 Stat. 1678 (42 U.S.C. 1857c-6, 1857c-9). Subpart B also issued under sec. 301(a) of the Clean Air Act, as amended by sec. 15(c)(2) of Pub. L. 91-604, 84 Stat. 1713 (42 U.S.C. 1857g).

3. Section 60.1 is revised to read as follows:

§ 60.1 Applicability.

Except as provided in Subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

4. Part 60 is amended by adding Subpart B as follows:

Subpart B—Adoption and Submittal of State Plans for Designated Facilities

§ 60.20 Applicability.

The provisions of this subpart apply to States upon publication of a final guideline document under § 60.22(a).

§ 60.21 Definitions.

Terms used but not defined in this subpart shall have the meaning given them in the Act and in subpart A:

(a) "Designated pollutant" means any air pollutant, emissions of which are subject to a standard of performance for new stationary sources but for which air quality criteria have not been issued, and which is not included on a list published under section 108(a) or section 112(b)(1)(A) of the Act.

(b) "Designated facility" means any existing facility (see § 60.2(aa)) which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility (see § 60.2(e)).

(c) "Plan" means a plan under section 111(d) of the Act which establishes emission standards for designated pollutants from designated facilities and provides for the implementation and enforcement of such emission standards.

(d) "Applicable plan" means the plan, or most recent revision thereof, which has been approved under § 60.27(b) or promulgated under § 60.27(d).

(e) "Emission guideline" means a guideline set forth in subpart C of this part, or in a final guideline document published under § 60.22(a), which reflects the degree of emission reduction achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated for designated facilities.

(f) "Emission standard" means a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, or prescribing equipment specifications for control of air pollution emissions.

(g) "Compliance schedule" means a legally enforceable schedule specifying a date or dates by which a source or category or sources must comply with specific emission standards contained in a plan or with any increments of progress to achieve such compliance.

(h) "Increments of progress" means steps to achieve compliance which must be taken by an owner or operator of a designated facility, including:

(1) Submittal of a final control plan for the designated facility to the appropriate air pollution control agency;

(2) Awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification.

(3) Initiation of on-site construction or installation of emission control equipment or process change;

(4) Completion of on-site construction or installation of emission control equipment or process change; and

(5) Final compliance.

(i) "Region" means an air quality control region designated under section 107 of the Act and described in Part 81 of this chapter.

(j) "Local agency" means any local governmental agency.

§ 60.22 Publication of guideline documents, emission guidelines, and final compliance times.

(a) After promulgation of a standard of performance for the control of a designated pollutant from affected facilities, the Administrator will publish a draft guideline document containing information pertinent to control of the designated pollutant from designated facilities. Notice of the availability of the draft guideline document will be published in the FEDERAL REGISTER, and public comments on its contents will be invited. After consideration of public comments, a final guideline document will be published and notice of its availability will be published in the FEDERAL REGISTER.

(b) Guideline documents published under this section will provide information for the development of State plans, such as:

(1) Information concerning known or suspected endangerment of public health or welfare caused, or contributed to, by the designated pollutant.

(2) A description of systems of emission reduction which, in the judgment of the Administrator, have been adequately demonstrated.

(3) Information on the degree of emission reduction which is achievable with each system, together with information on the costs and environmental effects of applying each system to designated facilities.

(4) Incremental periods of time normally expected to be necessary for the design, installation, and startup of identified control systems.

(5) An emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved. The Administrator will specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.

(6) Such other available information as the Administrator determines may contribute to the formulation of State plans.

(c) Except as provided in paragraph (d)(1) of this section, the emission guidelines and compliance times referred to in paragraph (b)(5) of this section will be proposed for comment upon publication of the draft guideline document, and after consideration of comments will be promulgated in Subpart C of this part with such modifications as may be appropriate.

(d)(1) If the Administrator determines that a designated pollutant may cause or contribute to endangerment of public welfare, but that adverse effects on public health have not been demonstrated, he will include the determination in the draft guideline document and in the FEDERAL REGISTER notice of its availability. Except as provided in paragraph (d)(2) of this section, paragraph (c) of this section shall be inapplicable in such cases.

(2) If the Administrator determines at any time on the basis of new information that a prior determination under paragraph (d)(1) of this section is incorrect or no longer correct, he will publish notice of the determination in the FEDERAL REGISTER, revise the guideline document as necessary under paragraph (a) of this section, and propose and promulgate emission guidelines and compliance times under paragraph (c) of this section.

§ 60.23 Adoption and submittal of State plans; public hearings.

(a)(1) Within nine months after notice of the availability of a final guideline document is published under § 60.22 (a), each State shall adopt and submit to the Administrator, in accordance with § 60.4, a plan for the control of the designated pollutant to which the guideline document applies.

(2) Within nine months after notice of the availability of a final revised guideline document is published as provided in § 60.22(d)(2), each State shall adopt and submit to the Administrator any plan revision necessary to meet the requirements of this subpart.

(b) If no designated facility is located within a State, the State shall submit a letter of certification to that effect to the Administrator within the time specified in paragraph (a) of this section. Such certification shall exempt the State from the requirements of this subpart for that designated pollutant.

(c)(1) Except as provided in paragraphs (c)(2) and (c)(3) of this section, the State shall, prior to the adoption of any plan or revision thereof, conduct one or more public hearings within the State on such plan or plan revision.

(2) No hearing shall be required for any change to an increment of progress in an approved compliance schedule unless the change is likely to cause the facility to be unable to comply with the final compliance date in the schedule.

(3) No hearing shall be required on an emission standard in effect prior to the effective date of this subpart if it was adopted after a public hearing and is at least as stringent as the corresponding emission guideline specified in the applicable guideline document published under § 60.22(a).

(d) Any hearing required by paragraph (c) of this section shall be held only after reasonable notice. Notice shall be given at least 30 days prior to the date of such hearing and shall include:

(1) Notification to the public by prominently advertising the date, time, and place of such hearing in each region affected;

(2) Availability, at the time of public announcement, of each proposed plan or revision thereof for public inspection in at least one location in each region to which it will apply;

(3) Notification to the Administrator;

(4) Notification to each local air pollution control agency in each region to which the plan or revision will apply; and

(5) In the case of an interstate region, notification to any other State included in the region.

(e) The State shall prepare and retain, for a minimum of 2 years, a record of each hearing for inspection by any interested party. The record shall contain, as a minimum, a list of witnesses together with the text of each presentation.

(f) The State shall submit with the plan or revision:

(1) Certification that each hearing required by paragraph (c) of this section was held in accordance with the notice required by paragraph (d) of this section; and

(2) A list of witnesses and their organizational affiliations, if any, appearing at the hearing and a brief written summary of each presentation or written submission.

(g) Upon written application by a State agency (through the appropriate Regional Office), the Administrator may approve State procedures designed to insure public participation in the matters for which hearings are required and public notification of the opportunity to participate if, in the judgment of the Administrator, the procedures, although different from the requirements of this subpart, in fact provide for adequate notice to and participation of the public. The Administrator may impose such conditions on his approval as he deems necessary. Procedures approved under this section shall be deemed to satisfy the requirements of this subpart regarding procedures for public hearings.

§ 60.24 Emission standards and compliance schedules.

(a) Each plan shall include emission standards and compliance schedules.

(b)(1) Emission standards shall prescribe allowable rates of emissions except when it is clearly impracticable. Such cases will be identified in the guideline documents issued under § 60.22. Where emission standards prescribing equipment specifications are established, the plan shall, to the degree possible, set forth the emission reductions achievable by implementation of such specifications, and may permit compliance by the use of equipment determined by the State to be equivalent to that prescribed.

(2) Test methods and procedures for determining compliance with the emission standards shall be specified in the plan. Methods other than those specified in Appendix A to this part may be specified in the plan if shown to be equivalent or alternative methods as defined in § 60.2 (t) and (u).

(3) Emission standards shall apply to all designated facilities within the State. A plan may contain emission standards adopted by local jurisdictions provided that the standards are enforceable by the State.

(c) Except as provided in paragraph (f) of this section, where the Administrator has determined that a designated pollutant may cause or contribute to endangerment of public health, emission standards shall be no less stringent than the corresponding emission guideline(s) specified in subpart C of this part, and final compliance shall be required as expeditiously as practicable but no later than the compliance times specified in Subpart C.

(d) Where the Administrator has determined that a designated pollutant may cause or contribute to endangerment of public welfare but that adverse effects on public health have not been demonstrated, States may balance the emission guidelines, compliance times, and other information provided in the applicable guideline document against other factors of public concern in establishing emission standards, compliance schedules, and variances. Appropriate consideration shall be given to the factors specified in § 60.22(b) and to information presented at the public hearing(s) conducted under § 60.23(e).

(e)(1) Any compliance schedule extending more than 12 months from the date required for submittal of the plan shall include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities. Increments of progress shall include, where practicable, each increment of progress specified in § 60.21(h) and shall include such additional increments of progress as may be necessary to permit close and effective supervision of progress toward final compliance.

(2) A plan may provide that compliance schedules for individual sources or categories of sources will be formulated after plan submittal. Any such schedule shall be the subject of a public hearing held according to § 60.23 and shall be submitted to the Administrator within 60 days after the date of adoption of the schedule but in no case later than the date prescribed for submittal of the first semiannual report required by § 60.25(e).

(f) On a case-by-case basis for particular designated facilities, or classes of facilities, States may provide for the application of less stringent emission standards or longer compliance schedules than those otherwise required by paragraph (c) of this section, provided that the State demonstrates with respect to each such facility (or class of facilities):

(1) Unreasonable cost of control resulting from plant age, location, or basic process design;

(2) Physical impossibility of installing necessary control equipment; or

(3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

(g) Nothing in this subpart shall be construed to preclude any State or political subdivision thereof from adopting or enforcing (1) emission standards more stringent than emission guidelines specified in subpart C of this part or in applicable guideline documents or (2) compliance schedules requiring final compliance at earlier times than those specfied in subpart C or in applicable guideline documents.

§ 60.25 Emission inventories, source surveillance, reports.

(a) Each plan shall include an inventory of all designated facilities, including emission data for the designated pollutants and information related to emissions as specified in Appendix D to this part. Such data shall be summarized in the plan, and emission rates of designated pollutants from designated facilities shall be correlated with applicable emission standards. As used in this subpart, "correlated" means presented in such a manner as to show the relationship between measured or estimated amounts of emissions and the amounts of such emissions

allowable under applicable emission standards.

(b) Each plan shall provide for monitoring the status of compliance with applicable emission standards. Each plan shall, as a minimum, provide for:

(1) Legally enforceable procedures for requiring owners or operators of designated facilities to maintain records and periodically report to the State information on the nature and amount of emissions from such facilities, and/or such other information as may be necessary to enable the State to determine whether such facilities are in compliance with applicable portions of the plan.

(2) Periodic inspection and, when applicable, testing of designated facilities.

(c) Each plan shall provide that information obtained by the State under paragraph (b) of this section shall be correlated with applicable emission standards (see § 60.25(a)) and made available to the general public.

(d) The provisions referred to in paragraphs (b) and (c) of this section shall be specifically identified. Copies of such provisions shall be submitted with the plan unless:

(1) They have been approved as portions of a preceding plan submitted under this subpart or as portions of an implementation plan submitted under section 110 of the Act, and

(2) The State demonstrates:

(i) That the provisions are applicable to the designated pollutant(s) for which the plan is submitted, and

(ii) That the requirements of § 60.26 are met.

(e) The State shall submit reports on progress in plan enforcement to the Administrator on a semiannual basis, commencing with the first full report period after approval of a plan or after promulgation of a plan by the Administrator. The semiannual periods are January 1–June 30 and July 1–December 31. Information required under this paragraph shall be included in the semiannual reports required by § 51.7 of this chapter.

(f) Each progress report shall include:

(1) Enforcement actions initiated against designated facilities during the reporting period, under any emission standard or compliance schedule of the plan.

(2) Identification of the achievement of any increment of progress required by the applicable plan during the reporting period.

(3) Identification of designated facilities that have ceased operation during the reporting period

(4) Submission of emission inventory data as described in paragraph (a) of this section for designated facilities that were not in operation at the time of plan development but began operation during the reporting period

(5) Submission of additional data as necessary to update the information submitted under paragraph (a) of this section or in previous progress reports.

(6) Submission of copies of technical reports on all performance testing on designated facilities conducted under paragraph (b)(2) of this section, complete with concurrently recorded process data.

§ 60.26 Legal authority.

(a) Each plan shall show that the State has legal authority to carry out the plan, including authority to:

(1) Adopt emission standards and compliance schedules applicable to designated facilities.

(2) Enforce applicable laws, regulations, standards, and compliance schedules, and seek injunctive relief.

(3) Obtain information necessary to determine whether designated facilities are in compliance with applicable laws, regulations, standards, and compliance schedules, including authority to require recordkeeping and to make inspections and conduct tests of designated facilities.

(4) Require owners or operators of designated facilities to install, maintain, and use emission monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such facilities; also authority for the State to make such data available to the public as reported and as correlated with applicable emission standards.

(b) The provisions of law or regulations which the State determines provide the authorities required by this section shall be specifically identified. Copies of such laws or regulations shall be submitted with the plan unless:

(1) They have been approved as portions of a preceding plan submitted under this subpart or as portions of an implementation plan submitted under section 110 of the Act, and

(2) The State demonstrates that the laws or regulations are applicable to the designated pollutant(s) for which the plan is submitted.

(c) The plan shall show that the legal authorities specified in this section are available to the State at the time of submission of the plan. Legal authority adequate to meet the requirements of paragraphs (a)(3) and (4) of this section may be delegated to the State under section 114 of the Act.

(d) A State governmental agency other than the State air pollution control agency may be assigned responsibility for carrying out a portion of a plan if the plan demonstrates to the Administrator's satisfaction that the State governmental agency has the legal authority necessary to carry out that portion of the plan.

(e) The State may authorize a local agency to carry out a plan, or portion thereof, within the local agency's jurisdiction if the plan demonstrates to the Administrator's satisfaction that the local agency has the legal authority necessary to implement the plan or portion thereof, and that the authorization does not relieve the State of responsibility under the Act for carrying out the plan or portion thereof.

§ 60.27 Actions by the Administrator.

(a) The Administrator may, whenever he determines necessary, extend the period for submission of any plan or plan revision or portion thereof.

(b) After receipt of a plan or plan revision, the Administrator will propose the plan or revision for approval or disapproval. The Administrator will, within four months after the date required for submission of a plan or plan revision, approve or disapprove such plan or revision or each portion thereof.

(c) The Administrator will, after consideration of any State hearing record, promptly prepare and publish proposed regulations setting forth a plan, or portion thereof, for a State if:

(1) The State fails to submit a plan within the time prescribed;

(2) The State fails to submit a plan revision required by § 60.23(a)(2) within the time prescribed; or

(3) The Administrator disapproves the State plan or plan revision or any portion thereof, as unsatisfactory because the requirements of this subpart have not been met.

(d) The Administrator will, within six months after the date required for submission of a plan or plan revision, promulgate the regulations proposed under paragraph (c) of this section with such modifications as may be appropriate unless, prior to such promulgation, the State has adopted and submitted a plan or plan revision which the Administrator determines to be approvable

(e)(1) Except as provided in paragraph (e)(2) of this section, regulations proposed and promulgated by the Administrator under this section will prescribe emission standards of the same stringency as the corresponding emission guideline(s) specified in the final guideline document published under § 60.22(a) and will require final compliance with such standards as expeditiously as practicable but no later than the times specified in the guideline document.

(2) Upon application by the owner or operator of a designated facility to which regulations proposed and promulgated under this section will apply, the Administrator may provide for the application of less stringent emission standards or longer compliance schedules than those otherwise required by this section in accordance with the criteria specified in § 60.24(f).

(f) If a State failed to hold a public hearing as required by § 60.23(c), the Administrator will provide opportunity for a hearing within the State prior to promulgation of a plan under paragraph (d) of this section.

§ 60.28 Plan revisions by the State.

(a) Plan revisions which have the effect of delaying compliance with applicable emission standards or increments of progress or of establishing less stringent emission standards shall be submitted to the Administrator within 60 days after adoption in accordance with the procedures and requirements applicable to development and submission of the original plan.

(b) More stringent emission standards, or orders which have the effect of ac-

celerating compliance, may be submitted to the Administrator as plan revisions in accordance with the procedures and requirements applicable to development and submission of the original plan.

(c) A revision of a plan, or any portion thereof, shall not be considered part of an applicable plan until approved by the Administrator in accordance with this subpart.

§ 60.29 Plan revisions by the Administrator.

After notice and opportunity for public hearing in each affected State, the Administrator may revise any provision of an applicable plan if:

(a) The provision was promulgated by the Administrator, and

(b) The plan, as revised, will be consistent with the Act and with the requirements of this subpart.

5. Part 60 is amended by adding Appendix D as follows:

APPENDIX D—REQUIRED EMISSION INVENTORY INFORMATION

(a) Completed NEDS point source form(s) for the entire plant containing the designated facility, including information on the applicable criteria pollutants. If data concerning the plant are already in NEDS, only that information must be submitted which is necessary to update the existing NEDS record for that plant. Plant and point identification codes for NEDS records shall correspond to those previously assigned in NEDS; for plants not in NEDS, these codes shall be obtained from the appropriate Regional Office.

(b) Accompanying the basic NEDS information shall be the following information on each designated facility:

(1) The state and county identification codes, as well as the complete plant and point identification codes of the designated facility in NEDS. (The codes are needed to match these data with the NEDS data.)

(2) A description of the designated facility including, where appropriate:

(i) Process name.

(ii) Description and quantity of each product (maximum per hour and average per year).

(iii) Description and quantity of raw materials handled for each product (maximum per hour and average per year).

(iv) Types of fuels burned, quantities and characteristics (maximum and average quantities per hour, average per year).

(v) Description and quantity of solid wastes generated (per year) and method of disposal.

(3) A description of the air pollution control equipment in use or proposed to control the designated pollutant, including:

(i) Verbal description of equipment.

(ii) Optimum control efficiency, in percent. This shall be a combined efficiency when more than one device operate in series. The method of control efficiency determination shall be indicated (e.g., design efficiency, measured efficiency, estimated efficiency).

(iii) Annual average control efficiency, in percent, taking into account control equipment down time. This shall be a combined efficiency when more than one device operate in series.

(4) An estimate of the designated pollutant emissions from the designated facility (maximum per hour and average per year). The method of emission determination shall also be specified (e.g., stack test, material balance, emission factor).

(Secs. 111, 114, and 301 of the Clean Air Act, as amended by sec. 4(a) of Pub. L. 91-604, 84 Stat. 1678, and by sec. 15(c)(2) of Pub. L. 91-604, 84 Stat. 1713 (42 U.S.C. 1857c-6, 1857c-9, 1857g))

[FR Doc.75-30611 Filed 11-14-75;8:45 am]

22 Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 402-8]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Modification, Notification, and Reconstruction

On October 15, 1974 (39 FR 36946), under section 111 of the Clean Air Act, as amended (42 U.S.C. 1857), the Environmental Protection Agency (EPA) proposed amendments to the general provisions of 40 CFR Part 60. These amendments included additions and revisions to clarify the definition of the term "modification" appearing in the Act, to require notification of construction or potential modification, and to clarify when standards of performance are applicable to reconstructed sources. These regulations apply to all stationary sources constructed or modified after the proposal date of an applicable standard of performance.

Interested parties participated in the rulemaking by sending comments to EPA. Fifty-three comment letters were received, 43 of which came from industry, with the remainder coming from State and Federal agencies. Copies of the comment letters received and a summary of the comments with EPA's responses are available for public inspection and copying at the EPA Public Information Reference Unit, Room 2922 (EPA Library), 401 M Street SW., Washington, D.C. In addition, copies of the comment summary and Agency responses may be obtained upon written request from the EPA Public Information Center (PM-215), 401 M Street SW., Washington, D.C. 20460 (specify Public Comment Summary—Modification, Notification, and Reconstruction). The comments have been carefully considered, and where determined by the Administrator to be appropriate, changes have been made to the proposed regulations and are incorporated in the regulations promulgated herein. The most significant comments and the differences between the proposed and promulgated regulations are discussed below.

Terminology

Understandably there has been some confusion as to the difference between the various types of "sources" and "facilities" defined in § 60.2 of these regulations. Generally speaking, "sources" are entire plants, while "facilities" are identifiable pieces of process equipment or individual components which when taken together would comprise a source. "Affected facilities" are facilities subject to standards of performance, and are specifically identified in the first section of each subpart of Part 60. An "existing facility" is generally a piece of equipment or component of the same type as an affected facility, but which differs in that it was constructed prior to the date of proposal of an applicable standard of performance. This distinction is somewhat complicated because an existing facility which undergoes a modification within the meaning of the Act and these regulations becomes an affected facility. However, generally speaking, the distinction between "affected facilities" and "existing facilities" depends on the date of construction. The terms are intended to be the direct regulatory counterparts of the statutory definitions of "new source" and "existing source" appearing in section 111 of the Act.

"Designated facilities" form a subcategory of "existing facilities." A "designated facility" is an existing facility which emits a "designated pollutant," i.e., a pollutant which is neither a hazardous pollutant, as defined by section 112 of the Act, nor a pollutant subject to national ambient air quality standards. The term "designated facilities," however, has no special relevance to the issue of modification.

Definition of "Capital Expenditure"

Several commentators argued that the proposed definition of "capital expenditure," as applicable to the exemption for increasing the production rate of an existing facility in § 60.14(e)(2), was too vague. The regulations promulgated herein correct this deficiency by incorporating by reference and by requiring the application of the procedure contained in Internal Revenue Service Publication 534, which is available from any IRS office. The procedure set forth in IRS Publication 534 is relatively straightforward. First, the total cost of increasing the production or operating rate must be determined. All expenditures necessary to increasing the facility's operating rate must be included in this total. However, for purposes of § 60.14(e)(2) this amount must not be reduced by any "excluded additions," as defined in IRS Publication 534, as would be done for tax purposes. Next, the facility's basis (usually its cost), as defined by Section 1012 of the Internal Revenue Code, must be determined. If the product of the appropriate "annual asset guideline repair allowance percentage" tabulated in Publication 534 and the facility's basis exceeds the cost of increasing the operating rate, the change will not be treated as a modification. Conversely, if the cost of making the change is more than the above product and the emissions have increased, the change will be treated as a modification.

The advantage of adopting the procedure in IRS Publication 534 is that firm and precise guidance is provided as to what constitutes a capital expenditure. The procedure involves concepts and information which are available to all owners and operators and with which they are familiar, and it is the Administrator's opinion that it adequately responds to the complaints of vagueness made in comments.

Notification of Construction

The regulations promulgated herein contain a requirement that owners or operators notify EPA within 30 days of the commencement of construction of an affected facility. Some commentators, however, questioned the Agency's legal authority to require such a notification and questioned the need for such information.

Section 301(a) of the Act provides the Administrator authority to issue regulations "necessary to carry out his functions under [the] Act." The Agency has learned through experience with administering the new source performance standards that knowledge of the sources which may become subject to the standards is important to the effective implementation of section 111. This notification will not be used for approval or disapproval of the planned construction; the purpose is to allow the Administrator to locate sources which will be subject to the regulations appearing in this part, and to enable the Administrator to inform the sources about applicable regulations in an effort to minimize future problems. In the case of mass produced facilities, which are purchased by the ultimate user when construction is completed, the construction notification requirement will not apply. Notification prior to startup, however will still be required.

Use of Emission Factors

The proposed regulations listed emission factors as one possible method to be used in determining whether a facility has increased its emissions. Emission factors have two major advantages. First, they are inexpensive to use. Second, they may be applied prospectively, i.e., they can be used in some cases to determine whether a particular change *will* increase a facility's emissions before the change is implemented. This is important to owners or operators since they can thereby obtain advance notice of the consequences of proposed changes they are planning prior to commitment to a particular course of action. Emission factors do not, however, provide results as precise as other methods, such as actual stack testing. Nevertheless, in many cases the emission consequences of a proposed change can be reliably predicted by the use of emission factors. In such cases, where emissions will clearly increase or will clearly not increase, the Agency will rely primarily on emission factors. Only where the resulting change in emission rate is ambiguous, or where a dispute arises as to the result obtained by the use of emission factors, will other methods be used. Section 60.14(b) has been revised to reflect this policy.

The "Bubble Concept"

The phrase "bubble concept" has been used to refer to the trading off of emission increases from one facility undergoing a physical or operational change with emission reductions from another facility, in order to achieve no net increase in the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by the stationary source taken as a whole.

Several commentators suggested that the "bubble concept" be extended to cover "new construction." Under the proposed regulations, the "bubble concept" could be utilized to offset emission increases

from a facility undergoing a physical or operational change (as distinguished from a "new facility") at a lower economic cost than would arise if the facility undergoing the change were to be considered by EPA as being modified within the meaning of section 111 of the Act and consequently required to meet standards of performance. Under the suggested approach a new facility could be added to an existing source without having to meet otherwise applicable standards of performance, provided the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by the stationary source taken as a whole did not increase. If adopted, this suggestion could exempt most new construction at existing sources from having to comply with otherwise applicable standards of performance. Such an interpretation of the section 111 provisions of the Act would grant a significant and unfair economic advantage to owners or operators of existing sources replacing facilities with new construction as compared to someone wishing to construct an entirely new source.

If the bubble concept were extended to cover new construction, large sources of air pollution could avoid the application of new source performance standards indefinitely. Such sources could continually replace obsolete or worn out facilities with new facilities of the same type. If the same emission controls were adopted, no overall emission increase would result. In this manner, the source could continue indefinitely without ever being required to upgrade air pollution control systems to meet standards of performance for new facilities. The Administrator interprets section 111 to require that new producers of emissions be subject to the standards whether constructed at a new plant site or an existing one. Therefore, where a new facility is constructed, new source performance standards must be met. In situations involving physical or operational changes to an existing facility which increase emissions from that facility, greater flexibilty is permitted to avoid the imposition of large control costs if the projected increase can be offset by controlling other plant facilities.

Several commentators argued that if the Administrator adopted the proposed interpretation of the term "modification", which would consider a modification to have occurred even if there was only a relatively minor detectable emission rate increase (thus requiring application of standards of performance), the Administrator would in effect prevent owners or operators from implementing physical or operational changes necessary to switch from gas and oil to coal in comport with the President's policy of reducing gas and oil consumption. The Administrator has concluded that if such situations exist, they will be relatively rare and, in any event, will be peculiar to the group of facilities covered by a particular standard of performance rather than to all facilities in general. Therefore, the Administrator has further concluded that it would be more appropriate to consider such circumstances and possible avenues of relief in connection with the promulgation of or amendment to particular standards of performance rather than through the amendment of the general provisions of 40 CFR Part 60.

Where the use of the bubble concept is elected by an owner or operator, some guarantee is necessary to insure that emissions do not subsequently increase above the level present before the physical or operational change in question. For example, reducing a facility's operating rate is a permissible means of offsetting emission increases from another facility undergoing a physical or operational change. If the exemption provided by § 60.14(e)(2) as promulgated herein were subsequently used to increase the first facility's operating rate back to the prior level, the intent of the Act would be circumvented and the compliance measures previously adopted would be nullified. Therefore, in those cases where utilization of the exemptions under § 60.14(e)(2), (3), or (4) as promulgated herein would effectively negate the compliance measures originally adopted, use of those exemptions will not be permitted.

One limitation placed on utilization of the "bubble concept" by the proposed regulation was that emission reductions could be credited only if achieved at an "existing" or "affected" facility. The purpose of this requirement was to limit the "bubble concept" to those facilities which could be source tested by EPA reference methods. One commentator pointed out that some facilities other than "existing" or "affected" facilities (i.e., facilities of the type for which no standards have been promulgated) lend themselves to accurate emission measurement. Therefore, § 60.14(d) has been revised to permit emission reductions to be credited from all facilities whose emissions can be measured by reference, equivalent, or alternative methods, as defined in § 60.2 (s), (t), and (u). In addition, when a facility which cannot be tested by any of these methods is permanently closed, the regulations have been revised to permit emission rate reductions from such closures to be used to offset emission rate increases if methods such as emission factors clearly show, to the Administrator's satisfaction that the reduction offsets any increase. The regulation does not allow facilities which cannot be tested by any of these methods to reduce their production as a means of reducing emissions to offset emission rate increases because establishing allowable emissions for such facilities and monitoring compliance to insure that the allowable emissions are not exceeded would be very difficult and even impossible in many cases.

Also, under the proposed regulations applicable to the "bubble concept," actual emission testing was the only permissible method for demonstrating that there has been no increase in the total emission rate of any pollutant to which a standard applies from all facilities within the stationary source. Several commentators correctly argued that if methods such as emission factors are sufficiently accurate to determine emission rates under other sections of the regulation [i.e. § 60.14(b)], they should be adequate for the purposes of utilization of the bubble concept. Thus, the regulations have been revised to permit the use of emission factors in those cases where it can be demonstrated to the Administrator's satisfaction that they will clearly show that total emissions will or will not increase. Where the Administrator is not convinced of the reliability of emission factors in a particular case, other methods will be required.

Ownership Change

The regulation has been amended by adding § 60.14(e)(6) which states that a change in ownership or relocating a source does not by itself bring a source under these modification regulations.

Reconstruction

Several commentators questioned the Agency's legal authority to propose standards of performance on reconstructed sources. Many commentators further believed that the Agency is attempting to delete the emission increase requirement from the definition of modification. The Agency's actual intent is to prevent circumvention of the law. Section 111 of the Act requires compliance with standards of performance in two cases, new construction and modification. The reconstruction provision is intended to apply where an existing facility's components are replaced to such an extent that it is technologically and economically feasible for the reconstructed facility to comply with the applicable standards of performance. In the case of an entirely new facility the proper time to apply the best adequately demonstrated control technology is when the facility is originally constructed. As explained in the preamble to the proposed regulation, the purpose of the reconstruction provision is to recognize that replacement of many of the components of a facility can be substantially equivalent to totally replacing it at the end of its useful life with a newly constructed affected facility. For existing facilities which substantially retain their character as existing facilities, application of best adequately demonstrated control technology is considered appropriate when any physical or operational change is made which causes an increase in emissions to the atmosphere (this is modification). Thus, the criteria for "reconstruction" are independent from the criteria for "modification."

Sections 60.14 and 60.15 set up the procedures and criteria to be used in making the determination to apply best adequately demonstrated control technology to existing facilities to which some changes have been made.

Under the proposed regulations, the replacement of a substantial portion of an existing facility's components constituted reconstruction. Many commentators questioned the meaning of "substantial portion." After considering the comments and the vagueness of this term, the Agency decided to revise the proposed reconstruction provisions to

better clarify to owners or operators what actions they must take and what action the Administrator will take. Section 60.15 of the regulations as revised specifies that reconstruction occurs upon replacement of components if the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility and it is technologically and economically feasible for the facility after the replacements to comply with the applicable standards of performance. The 50 percent replacement criteria is designed merely to key the notification to the Administrator; it is not an independent basis for the Administrator's determination. The term "fixed capital cost" is defined as the capital needed to provide all the depreciable components and is intended to include such things as the costs of engineering, purchase, and installation of major process equipment, contractors' fees, instrumentation, auxiliary facilities, buildings, and structures. Costs associated with the purchase and installation of air pollution control equipment (e.g., baghouses, electrostatic precipitators, scrubbers, etc.) are not considered in estimating the fixed capital cost of a comparable entirely new facility unless that control equipment is required as part of the process (e.g., product recovery).

The revised § 60.15 leaves the final determination with the Administrator as to when it is technologically and economically feasible to comply with the applicable standards of performance. Further clarification and definition is not possible because the spectrum of replacement projects that will take place in the future at existing facilities is so broad that it is not possible to be any more specific. Section 60.15 sets forth the criteria which the Administrator will use in making his determination. For example, if the estimated life of the facility after the replacements is significantly less than the estimated life of a new facility, the replacement may not be considered reconstruction. If the equipment being replaced does not emit or cause an emission of an air pollutant, it may be determined that controlling the components that do emit air pollutants is not reasonable considering cost, and standards of performance for new sources should not be applied. If there is insufficient space after the replacements at an existing facility to install the necessary air pollution control system to comply with the standards of performance, then reconstruction would not be determined to have occurred. Finally, the Administrator will consider all technical and economic limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

While § 60.15 expresses the basic Agency policy and interpretation regarding reconstruction, individual subparts may refine and delimit the concept as applied to individual categories of facilities.

RESPONSE TO REQUESTS FOR DETERMINATION

Section 60.5 has been revised to indicate that the Administrator will make a determination of whether an action by an owner or operator constitutes reconstruction within the meaning of § 60.15. Also, in response to a public comment, a new § 60.5(b) has been added to indicate the Administrator's intention to respond to requests for determinations within 30 days of receipt of the request.

STATISTICAL TEST

Appendix C of the regulation incorporates a statistical procedure for determining whether an emission increase has occurred. Several individuals commented on the procedure as proposed. After considering all these comments and conducting further study into the subject, the Administrator has determined that a statistical procedure is substantially superior to a method comparing average emissions, and that no other statistical procedure is clearly superior to the one adopted (Student's t test). A more detailed analysis of this issue can be found in EPA's responses to the comments mentioned previously.

Effective date. These regulations are effective on December 16, 1975. Since they represent a clarification of the Agency's existing enforcement policy, good cause is found for not delaying the effective date, as required by 5 U.S.C. 553(d)(3). However, the regulations will, in effect, apply retroactively to any enforcement activity now in progress since they do reflect present Agency policy.

(Sections 111, 114, and 301 of the Clean Air Act, as amended (42 U.S.C. 1857c-6, 1857c-9, and 1857g))

Dated: December 8, 1975.

RUSSELL E. TRAIN,
Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. The table of sections is amended by adding §§ 60.14 and 60.15 and Appendix C as follows:

Subpart A—General Provisions

* * * * *

Sec.
60.14 Modification.
60.15 Reconstruction.

* * * * *

Appendix C—Determination of Emission Rate Change.

2. In § 60.2, paragraphs (d) and (h) are revised and paragraphs (aa) and (bb) are added as follows:

§ 60.2 Definitions.

* * * * *

(d) "Stationary source" means any building, structure, facility, or installation which emits or may emit any air pollutant and which contains any one or combination of the following:

(1) Affected facilities.

(2) Existing facilities.

(3) Facilities of the type for which no standards have been promulgated in this part.

* * * * *

(h) "Modification" means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

* * * * *

(aa) "Existing facility" means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type.

(bb) "Capital expenditure" means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable "annual asset guideline repair allowance percentage" specified in the latest edition of Internal Revenue Service Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code.

3. Section 60.5 is revised to read as follows:

§ 60.5 Determination of construction or modification.

(a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.

(b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

4. In § 60.7, paragraphs (a)(1) and (a)(2) are revised, and paragraphs (a)(3), (a)(4), and (e) are added as follows:

§ 60.7 Notification and recordkeeping.

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification as follows:

(1) A notification of the date construction (or reconstruction as defined under § 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

(2) A notification of the anticipated date of initial startup of an affected facility postmarked not more than 60 days nor less than 30 days prior to such date.

(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is spe-

cifically exempted under an applicable subpart or in § 60.14(e) and the exemption is not denied under § 60.14(d)(4). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

* * * * *

(e) If notification substantially similar to that in paragraph (a) of this section is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section.

5. Subpart A is amended by adding §§ 60.14 and 60.15 as follows:

§ 60.14 Modification.

(a) Except as provided under paragraphs (d), (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

(b) Emission rate shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors," EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrate that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in paragraph (b)(1) of this section does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in paragraph (b)(1) of this section. When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in Appendix C of this part shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

(d) A modification shall not be deemed to occur if an existing facility undergoes a physical or operational change where the owner or operator demonstrates to the Administrator's satisfaction (by any of the procedures prescribed under paragraph (b) of this section) that the total emission rate of any pollutant has not increased from all facilities within the stationary source to which appropriate reference, equivalent, or alternative methods, as defined in § 60.2 (s), (t) and (u), can be applied. An owner or operator may completely and permanently close any facility within a stationary source to prevent an increase in the total emission rate regardless of whether such reference, equivalent or alternative method can be applied, if the decrease in emission rate from such closure can be adequately determined by any of the procedures prescribed under paragraph (b) of this section. The owner or operator of the source shall have the burden of demonstrating compliance with this section.

(1) Such demonstration shall be in writing and shall include: (i) The name and address of the owner or operator.

(ii) The location of the stationary source.

(iii) A complete description of the existing facility undergoing the physical or operational change resulting in an increase in emission rate, any applicable control system, and the physical or operational change to such facility.

(iv) The emission rates into the atmosphere from the existing facility of each pollutant to which a standard applies determined before and after the physical or operational change takes place, to the extent such information is known or can be predicted.

(v) A complete description of each facility and the control systems, if any, for those facilities within the stationary source where the emission rate of each pollutant in question will be decreased to compensate for the increase in emission rate from the existing facility undergoing the physical or operational change.

(vi) The emission rates into the atmosphere of the pollutants in question from each facility described under paragraph (d)(1)(v) of this section both before and after the improvement or installation of any applicable control system or any physical or operational changes to such facilities to reduce emission rate.

(vii) A complete description of the procedures and methods used to determine the emission rates.

(2) Compliance with paragraph (d) of this section may be demonstrated by the methods listed in paragraph (b) of this section, where appropriate. Decreases in emissions resulting from requirements of a State implementation plan approved or promulgated under Part 52 of this chapter will not be acceptable. The required reduction in emission rate may be accomplished through the installation or improvement of a control system or through physical or operational changes to facilities including reducing the production of a facility or closing a facility.

(3) Emission rates established for the existing facility which is undergoing a physical or operational change resulting in an increase in the emission rate, and established for the facilities described under paragraph (d)(1)(v) of this section shall become the baseline for determining whether such facilities undergo a modification or are in compliance with standards.

(4) Any emission rate in excess of that rate established under paragraph (d)(3) of this section shall be a violation of these regulations except as otherwise provided in paragraph (e) of this section. However, any owner or operator electing to demonstrate compliance under this paragraph (d) must apply to the Administrator to obtain the use of any exemptions under paragraphs (e)(2), (e)(3), and (e)(4) of this section. The Administrator will grant such exemption only if, in his judgment, the compliance originally demonstrated under this paragraph will not be circumvented or nullified by the utilization of the exemption.

(5) The Administrator may require the use of continuous monitoring devices and compliance with necessary reporting procedures for each facility described in paragraph (d)(1)(iii) and (d)(1)(v) of this section.

(e) The following shall not, by themselves, be considered modifications under this part:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of paragraph (c) of this section and § 60.15.

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on the stationary source containing that facility.

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by § 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction

specifications, as amended, prior to the change. Conversion to coal required for energy considerations, as specified in section 119(d)(5) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in paragraphs (a) or (d) of this section, compliance with all applicable standards must be achieved.

§ 60.15 Reconstruction.

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost" means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by paragraph (d) of this section and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under paragraph (e) shall be based on:

(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;

(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;

(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and

(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

6. Part 60 is amended by adding Appendix C as follows:

APPENDIX C—DETERMINATION OF EMISSION RATE CHANGE

1. *Introduction.*

1.1 The following method shall be used to determine whether a physical or operational change to an existing facility resulted in an increase in the emission rate to the atmosphere. The method used is the Student's *t* test, commonly used to make inferences from small samples.

2. *Data.*

2.1 Each emission test shall consist of n runs (usually three) which produce n emission rates. Thus two sets of emission rates are generated, one before and one after the change, the two sets being of equal size.

2.2 When using manual emission tests, except as provided in § 60.8(b) of this part, the reference methods of Appendix A to this part shall be used in accordance with the procedures specified in the applicable subpart both before and after the change to obtain the data.

2.3 When using continuous monitors, the facility shall be operated as if a manual emission test were being performed. Valid data using the averaging time which would be required if a manual emission test were being conducted shall be used.

3. *Procedure.*

3.1 Subscripts a and b denote prechange and postchange respectively.

3.2 Calculate the arithmetic mean emission rate, $\bar{E}$, for each set of data using Equation 1.

$$\bar{E}=\sum_{i=1}^{n}\frac{E_i}{n}=\frac{E_1+E_2\ldots+E_n}{n} \quad (1)$$

where:

E_i = Emission rate for the i th run.

n = number of runs

3.3 Calculate the sample variance, S^2, for each set of data using Equation 2.

$$S^2=\frac{\sum_{i=1}^{n}(E_i-\bar{E})^2}{n-1}=\frac{\sum_{i=1}^{n}E_i^2-\left(\sum_{i=1}^{n}E_i\right)^2\Big/n}{n-1} \quad (2)$$

3.4 Calculate the pooled estimate, S_p, using Equation 3.

$$S_p=\left[\frac{(n_a-1)\,S_a^2+(n_b-1)\,S_b^2}{n_a+n_b-2}\right]^{1/2} \quad (3)$$

3.5 Calculate the test statistic, t, using Equation 4.

$$t=\frac{\bar{E}_b-\bar{E}_a}{S_p\left[\frac{1}{n_a}+\frac{1}{n_b}\right]^{1/2}} \quad (4)$$

4. *Results.*

4.1 If $\bar{E}_b>\bar{E}_a$ and $t>t'$, where t' is the critical value of t obtained from Table 1, then with 95% confidence the difference between $\bar{E}_b$ and $\bar{E}_a$ is significant, and an increase in emission rate to the atmosphere has occurred.

TABLE 1

Degree of freedom (n_a+n_b-2):	t' (95 percent confidence level)
2	2.920
3	2.353
4	2.132
5	2.015
6	1.943
7	1.895
8	1.860

For greater than 8 degrees of freedom, see any standard statistical handbook or text.

5.1 Assume the two performance tests produced the following set of data:

Test a:	Test b
Run 1. 100	115
Run 2. 95	120
Run 3. 110	125

5.2 Using Equation 1—

$$\bar{E}_a=\frac{100+95+110}{3}=102$$

$$\bar{E}_b=\frac{115+120+125}{3}=120$$

5.3 Using Equation 2—

$$S_a^2=\frac{(100-102)^2+(95-102)^2+(110-102)^2}{3-1}=58.5$$

$$S_b^2=\frac{(115-120)^2+(120-120)^2+(125-120)^2}{3-1}=25$$

5.4 Using Equation 3—

$$S_p=\left[\frac{(3-1)\ (58.5)+(3-1)\ (25)}{3+3-2}\right]^{1/2}=6.46$$

5.5 Using Equation 4—

$$t=\frac{120-102}{6.46\left[\frac{1}{3}+\frac{1}{3}\right]^{1/2}}=3.412$$

5.6 Since $(n_1+n_2-2)=4$, $t'=2.132$ (from Table 1). Thus since $t>t'$ the difference in the values of $\bar{E}_a$ and $\bar{E}_b$ is significant, and there has been an increase in emission rate to the atmosphere.

6. *Continuous Monitoring Data.*

6.1 Hourly averages from continuous monitoring devices, where available, should be used as data points and the above procedure followed.

(Secs. 111 and 114 of the Clean Air Act, as amended by sec. 4(a) of Pub. L. 91-604, 84 Stat 1678 (42 U.S.C. 1857c-6, 1857c-9))

[FR Doc.75-33612 Filed 12-15-75;8:45 am]

23 [FRL 471-6]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Emission Monitoring Requirements and Revisions to Performance Testing Methods; Correction

In FR Doc. 75-26565 appearing at page 46250 in the FEDERAL REGISTER of October 6, 1975, the following changes should be made in Appendix B:

1 On page 46260, paragraph 4 3, line 21 is corrected to read as follows:

$\log (1-0_1) = (1_1/1_2) \log (1-0_2)$

2. On page 46263, paragraph 4.1, line 8 is corrected to read as follows:

of an air preheater in a steam generating

3. On page 46269, paragraph 7.2.1, the definition of $C.I._{\infty}$ is corrected to read as follows:

$C.I._{\infty}$=95 percent confidence interval estimates of the average mean value

Dated: December 16, 1975.

ROGER STRELOW,
Assistant Administrator for Air and Waste Management.

[FR Doc.75-34514 Filed 12-19-75,8.45 am]

[FRL 423-7]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Emission Monitoring Requirements and Revisions to Performance Testing Methods

Correction

In FR Doc. 75-26565, appearing at page 46250 in the issue for Monday, October 6, 1975, the following changes should be made:

1. In the first paragraph on page 46250, the words "reduction, and reporting requirements" should be inserted immediately following the eighth line.

2. In the seventh from last line of the first full paragraph on page 46254, the parenthetical phrase should read, "October 6, 1975".

3. In the second line of the second full paragraph on page 46254, the next to last word, now reading "capacity", should read "opacity".

4 In paragraph (c)(2)(iii) of § 60.13 on page 46255, the parenthetical phrase "(date of promulgation" should read, "October 6, 1975".

5. In § 60.13, the paragraphs designated (g)(1) and (g)(1)(i) through (ix) on page 46256 should be designated paragraph (i) and (i) 1 through (9).

6. In the second line of the formula in paragraph (f)(4) of § 60 45 on page 46257, the figure now reading "6.34" should read "3 64".

7. The last line of the first paragraph in Appendix B on page 46259 should be changed to read "tinuous measurement of the opacity of stack emissions".

8. The paragraph now numbered "22" in Appendix B on page 46259 should be numbered "2.2".

9. In the next to last line of paragraphs 9.1.1 and 7.1.1 on pages 46261 and 46264 respectively "x" should read "x"

10. The first column in the table in paragraph 7 1 2 on page 46264, the first column should be headed by the letter "n" and figures 1 through 10 should read 2 through 11.

24 SUBCHAPTER C—AIR PROGRAMS

[FRL 474-3]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCE

Delegation of Authority to State of Maine

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of Maine on November 3, 1975, EPA is today amending 40 CFR 60.4, *Address*, to reflect this delegation. A Notice announcing this delegation is published today in the FEDERAL REGISTER.[1] The amended § 60.4, which adds the address of the Maine Department of Environmental Protection to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on October 7, 1975, and it serves no purpose to delay the technical change of this addition to the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended.

(42 U.S.C. 1857c-6)

Dated: December 22, 1975.

STANLEY W. LEGRO,
Assistant Administrator for Enforcement.

[1] See FR Doc. 75-35063 appearing elsewhere in the Notices section of today's FEDERAL REGISTER.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (U) to read as follows:

§ 60.4 Address.

* * * * * *

(b) * * *

(U) State of Maine, Department of Environmental Protection, State House, Augusta, Maine 04330.

* * * * * *

[FR Doc.75-35065 Filed 12-29-75;8:45 am]

25

[FRL 477-7]

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to the State of Michigan

Pursuant to the delegation of authority to implement and enforce the standards of performance for new stationary sources (NSPS) to the State of Michigan on November 5, 1975, EPA is today amending 40 CFR 60.4 *Address*, to reflect this delegation.[1] The amended § 60.4, which adds the address of the Air Pollution Control Division, Michigan Department of Natural Resources to that list of addresses to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must be sent, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on November 5, 1975, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

[1] A Notice announcing this delegation is published in the Notices section of this issue.

This rulemaking is effective immediately, and is issued under the authority of section 111 of the Clean Air Act, as amended. 42 U.S.C. 1857c-6.

Dated: December 31, 1975.

STANLEY W. LEGRO,
Assistant Administrator for Enforcement.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulation is amended as follows:

1. In § 60.4, paragraph (b) is amended by revising paragraph (b) X, to read as follows:

60.4 Address.

* * * * *

[FRL 447-8]

(b) * * *

(A)-(W) * * *

(X)—State of Michigan, Air Pollution Control Division, Michigan Department of Natural Resources, Stevens T Mason Building, 8th Floor, Lansing, Michigan 48926

* * * * *

[FR Doc.76-847 Filed 1-12-76,8 45 am]

26

[FRL 462-7]

PART 60 STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Coal Preparation Plants

On October 24, 1974 (39 FR 37922), under section 111 of the Clean Air Act, as amended, the Environmental Protection Agency (EPA) proposed standards of performance for new and modified coal preparation plants. Interested parties were afforded an opportunity to participate in the rulemaking by submitting written comments. Twenty-seven comment letters were received; six from coal companies, four from Federal agencies, four from steel companies, four from electric utility companies, three from State and local agencies, three from coal industry associations and three from other interested parties.

Copies of the comment letters and a supplemental volume of background information which contains a summary of the comments with EPA's responses are available for public inspection and copying at the U.S. Environmental Protection Agency, Public Information Reference Unit, Room 2922, 401 M Street, S.W., Washington, D.C. 20460. In addition, the supplemental volume of background information which contains copies of the comment summary with EPA's responses may be obtained upon written request from the EPA Public Information Center (PM-215), 401 M Street S.W., Washington, D.C. 20460 (specify Background Information for Standards of Performance: Coal Preparation Plants, Volume 3: Supplemental Information). The comments have been carefully considered, and where determined by the Administrator to be appropriate, changes have been made to the proposed regulations and are incorporated in the regulations promulgated herein.

The bases for the proposed standards are presented in "Background Information for Standards of Performance: Coal Preparation Plants" (EPA 450/2-74-021a, b). Copies of this document are available on request from the Emission Standards Protection Agency, Research Triangle and Engineering Division, Environmental Park, North Carolina 27711, Attention: Mr. Don R. Goodwin.

Summary of Regulation. The promulgated standards of performance regulate particulate matter emissions from coal preparation and handling facilities processing more than 200 tons/day of bituminous coal (regardless of their location) as follows: (1) emissions from thermal dryers may not exceed 0.070 g/dscm (0.031 gr/dscf) and 20% opacity, (2) emissions from pneumatic coal cleaning equipment may not exceed 0.040 g/dscm (0.018 gr/ dscf) and 10% opacity, and (3) emissions from coal handling and storage equipment (processing nonbituminous as well as bituminous coal) may not exceed 20% opactity.

Significant Comments and Revisions to the Proposed Regulations. Many of the comment letters received by EPA contained multiple comments. These are summarized as follows with discussions of any significant differences between the proposed and promulgated regulations.

1. *Applicability.*—Comments were received noting that the proposed standards would apply to any coal handling operation regardless of size and would require even small tipple operations and domestic coal distributors to comply with the proposed standards for fugitive emissions. In addition, underground mining activities may have been inadvertently included under the proposed standards. EPA did not intend to regulate either these small sources or underground mining activities. Only sources which break, crush, screen, clean, or dry large amounts of coal were intended to be covered. Sources which handle large amounts of coal would include coal handling operations at sources such as barge loading facilities, power plants, coke ovens, etc. as well as plants that primarily clean and/or dry coal. EPA concluded that sources not intended to be covered by the regulation handle less than 200 tons/day; therefore, the regulation promulgated herein exempts such sources.

Comments were received questioning the application of the standards to facilities processing nonbituminous coals (including lignite). As was stated in the preamble to the proposed regulation, it is intended for the standards to have broad applicability when appropriate. At the time the regulation was proposed, EPA considered the parameters relating to the control of emissions from thermal

dryers to be sufficiently similar, whether bituminous or nonbituminous coal was being dried. Since the time of proposal, EPA has reconsidered the application of standards to the thermal drying of nonbituminous coal. It has concluded that such application is not prudent in the absence of specific data demonstrating the similarity of the drying characteristics and emission control characteristics to those of bituminous coal. There are currently very few thermal dryers or pneumatic air cleaners processing nonbituminous fuels. The facilities tested by EPA to demonstrate control equipment representative of best control technology were processing bituminous coal. Since the majority of the EPA test data and other information used to develop the standards are based upon bituminous coal processing, the particulate matter standards for thermal dryers and pneumatic coal cleaning equipment have been revised to apply only to those facilities processing bituminous coal.

The opacity standard for control of fugitive emissions is applicable to nonbituminous as well as bituminous coal since nonbituminous processing facilities will utilize similar equipment for transporting, screening, storing, and loading coal, and the control techniques applicable for minimizing fugitive particulate matter emissions will be the same regardless of the type of coal processed. Typically enclosures with some type of low energy collectors are utilized. The opacity of emissions can also be reduced by effectively covering or sealing the process from the atmosphere so that any avenues for escaping emissions are small. By minimizing the number and the dimensions of the openings through which fugitive emissions can escape, the opacity and the total mass rate of emissions can be reduced independently of the air pollution control devices. Also, water sprays have been demonstrated to be very effective for suppressing fugitive emissions and can be used to control even the most difficult fugitive emission problems. Therefore, the control of fugitive emissions at all facilities will be required since there are several control techniques that can be applied regardless of the type of coal processed.

2. *Thermal dryer standard.*—One commentator presented data and calculations which indicated that because of the large amount of fine particles in the coal his company processes, compliance with the proposed standard would require the application of a venturi scrubber with a pressure drop of 50 to 52 inches of water gage. The proposed standard was based on the application of a venturi scrubber with a pressure drop of 25 to 35 inches. EPA thoroughly evaluated this comment and concluded that the commentator's calculations and extrapolations could have represented the actual situation. Rather than revise the standard on the basis of the commentator's estimates, EPA decided to perform emission tests at a plant which processes the coal under question. The plant tested is controlled with a venturi scrubber and was operated at a pressure drop of 29 inches during the emission tests. These tests showed emissions of 0.080 to 0.134 g/dscm (0.035 to 0.058 gr/dscf). These results are numerically greater than the proposed standard; however, calculations indicate that if the pressure drop were increased from 29 inches to 41 inches, the proposed standard would be achieved. Supplemental information regarding estimates of emission control needed to achieve the mass standard is contained in Section II, Volume 3 of the supplemental background information document.

Since the cost analysis of the proposed standard was based on a venturi scrubber operating at 25 to 35 inches venturi pressure loss, the costs of operating at higher pressure losses were evaluated. These results indicated that the added cost of controlling pollutants to the level of the proposed standard is only 14 cents per ton of plant product even if a 50 inch pressure loss were used, and only five cents per ton in excess of the average control level required by state regulations in the major coal producing states. In comparison to the $18.95 per ton delivered price of U.S. coal in 1974 and even higher prices today, a maximum five cents per ton economic impact attributable to these regulations appears almost negligible. The total impact of 14 cents per ton for controlling particulate matter emissions can easily be passed along to the customer since the demand for thermal drying due to freight rate savings, the elimination of handling problems due to freezing, and the needs of the customer's process (coke ovens must control bulk density and power plants must control plugging of pulverizers) will remain unaffected by these regulations. Therefore, the economic impact of the standard upon thermal drying will not be large and the inflationary impact of the standard on the price of coal will be insignificant (one percent or less). From the standpoint of energy consumption, the power requirements of the air pollution control equipment are exponentially related to the control level such that a level of diminishing return is reached. Because the highest pressure loss that has been demonstrated by operation of a venturi scrubber on a coal dryer is 41 inches water gage, which is also the pressure loss estimated by a scrubber vendor to be needed to achieve the 70 mg/dscm standard, and because energy consumption increases dramatically at lower control levels (<70 mg/dscm), a particulate matter standard lower than 70 mg/dscm was not selected. At the 70 mg/dscm control level, the trade-off between control of emissions at the thermal dryer versus the increase in emissions at the power plant supplying the energy is favorable even though the mass quantity of all air pollutants emitted by the power plant (SO_2, NO_x, and particulate matter) are compared only to the reduction in thermal dryer particulate matter emissions. At lower than 70 mg/dscm, this trade-off is not as favorable due to the energy requirements of venturi scrubbers at higher pressure drops. For this source, alternative means of air pollution control have not been fully demonstrated. Having considered all comments on the particulate matter regulation proposed for thermal dryers, EPA finds no reason sufficient to alter the proposed standard of 70 mg/dscm except to restrict its applicability to thermal dryers processing bituminous coal.

3. *Location of thermal drying systems.*—Comments were received on the applicability of the standard for power plants with closed thermal drying systems where the air used to dry the coal is also used in the combustion process. As indicated in § 60.252(a), the standard is concerned only with effluents which are discharged into the atmosphere from the drying equipment. Since the pulverized coal transported by heated air is charged to the steam generator in a closed system, there is no discharge from the dryer directly to the atmosphere, therefore, these standards for thermal dryers are not applicable. Effluents from steam generators are regulated by standards previously promulgated (40 CFR Part 60 subpart D). However, these standards do apply to all bituminous coal drying operations that discharge effluent to the atmosphere regardless of their physical or geographical location. In additiona to thermal dryers located in coal preparation plants, usually in the vicinity of the mines, dryers used to preheat coal at coke ovens are alsoregulated by these standards. These coke oven thermal dryers used for preheating are similar in all respects, including the air pollution control equipment, to those used in coal preparation plants.

4. *Opacity standards.*—The opacity standards for thermal dryer and pneumatic coal cleaners were reevaluated as a result of revisions to Method 9 for conducting opacity observations (39 FR 39872). The opacity stndards were proposed prior to the revisions of Method 9 and were not based upon the concept of averaging sets of 24 observations for six-minute periods. As a result, the proposed standards were developed in relation to the peak emissions of the facility rather than the average emissions of six-minute periods. The opacity data collected by EPA have been reevaluated in accordance with the revised Method 9 procedures, and opacity standards for thermal dryers and pneumatic coal cleaners have been adjusted to levels consistent with these new procedures. The opacity standards for thermal dryers and pneumatic coal cleaners have been adjusted from 30 and 20 percent to 20 and 10 percent opacity, respectively. Since the proposed standards were based upon peak rather than average opacity, the revised standards are numerically lower. Each of these levels is justified based primarily upon six-minute averages of EPA opacity observations. These data are contained in Section III, Volume 3 of the supplemental background information document.

5. *Fugitive emission monitoring.*—Several commentators identified some difficulties with the proposed procedures for monitoring the surface moisture of thermally dried coal. The purpose of the proposed requirement was to determine the probability of fugitive emissions occuring from coal handling operations

and to estimate their extent. The commentators noted that the proposed A.S.T.M. measurement methods are difficult and cumbersome procedures not typically used by operating facilities. Also, it was noted that there is too little uniformity of techniques within industry for measuring surface moisture to specify a general method. Secondly, estimation of fugitive emissions from such data may not be consistent due to different coal characteristics. Since the opacity standard promulgated herein can readily be utilized by enforcement personnel, the moisture monitoring requirement is relatively unimportant. EPA has therefore eliminated this requirement from the regulation.

6. *Open storage piles.*—The proposed regulation applied the fugitive emission standard to coal storage systems, which were defined as any facility used to store coal. It was EPA's intention that this definition refer to some type of structure such as a bin, silo, etc. Several commentators objected to the potential application of the fugitive emission standard to open storage piles. Since the fugitive emission standard was not developed for application to open storage piles, the regulations promulgated herein clarifies that open storage piles of coal are not regulated by these standards.

7. *Thermal dryer monitoring equipment.*—A number of commentators felt that important variables were not being considered for monitoring venturi scrubber operation on thermal dryers. The proposed standards required monitoring the temperature of the gas from the thermal dryer and monitoring the venturi scrubber pressure loss. The promulgated standard requires, in addition to the above parameters, monitoring of the water supply pressure to the venturi scrubber. Direct measurement of the water flow rate was considered but rejected due to potential plugging problems as a result of solids typically found in recycled scrubber water. Also, the higher cost of a flow rate meter in comparison to a simpler pressure monitoring device was a factor in the selection of a water pressure monitor for verifying that the scrubber receives adequate water for proper operation. This revision to the regulations will insure monitoring of major air pollution control device parameters subject to variation which could go undetected and unnoticed and could grossly affect proper operation of the control equipment. A pressure sensor, two transmitters, and a two pen chart recorder for monitoring scrubber venturi pressure drop and water supply pressure, which are commercially available, will cost approximately two to three thousand dollars installed for each thermal dryer. This cost is only one-tenth of one percent of the total investment cost of a 500-ton-per-hour thermal dryer. The regulations also require monitoring of the thermal dryer exit temperature, but no added cost will result because this measurement system is normally supplied with the thermal drying equipment and is used as a control point for the process control system.

Effective date.—In accordance with section 111 of the Act, as amended, these regulations prescribing standards of performance for coal preparation plants are effective on January 15, 1976, and apply to thermal dryers, pneumatic coal cleaners, coal processing and conveying equipment, coal storage systems, and coal transfer and loading systems, the construction or modification of which was commenced after October 24, 1974.

Dated: January 8, 1976.

RUSSELL E. TRAIN,
Administrator.

Part 60 of Chapter I of Title 40 of the Code of Federal Regulations is amended as follows:

1. The table of contents is amended by adding subpart Y as follows:

* * * * *

Subpart Y—Standards of Performance for Coal Preparation Plants

Sec.
60.250 Applicability and designation of *affected facility.*
60.251 Definitions.
60.252 Standards for particulate matter
60.253 Monitoring of operations.
60.254 Test methods and procedures

AUTHORITY: Secs 111 and 114 of the Clean Air Act, as amended by sec. 4(a) of Pub. L. 91-604, 84 Stat. 1678 (42 U.S.C. 1857c-6, 1857 c-9).

2. Part 60 is amended by adding subpart Y as follows:

* * * * *

Subpart Y—Standards of Performance for Coal Preparation Plants

§ 60.250 Applicability and designation of affected facility.

The provisions of this subpart are applicable to any of the following affected facilities in coal preparation plants which process more than 200 tons per day: thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems.

§ 60.251 Definitions.

As used in this subpart, all terms not defined herein have the meaning given them in the Act and in subpart A of this part.

(a) "Coal preparation plant" means any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.

(b) "Bituminous coal" means solid fossil fuel classified as bituminous coal by A.S.T.M. Designation D-388-66.

(c) "Coal" means all solid fossil fuels classified as anthracite, bituminous, subbituminous, or lignite by A.S.T.M. Designation D-388-66.

(d) "Cyclonic flow" means a spiraling movement of exhaust gases within a duct or stack.

(e) "Thermal dryer" means any facility in which the moisture content of bituminous coal is reduced by contact with a heated gas stream which is exhausted to the atmosphere.

(f) "Pneumatic coal-cleaning equipment" means any facility which classifies bituminous coal by size or separates bituminous coal from refuse by application of air stream(s).

(g) "Coal processing and conveying equipment" means any machinery used to reduce the size of coal or to separate coal from refuse, and the equipment used to convey coal to or remove coal and refuse from the machinery. This includes, but is not limited to, breakers, crushers, screens, and conveyor belts.

(h) "Coal storage system" means any facility used to store coal except for open storage piles.

(i) "Transfer and loading system" means any facility used to transfer and load coal for shipment.

§ 60.252 Standards for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any thermal dryer gases which:

(1) Contain particulate matter in excess of 0.070 g/dscm (0.031 gr/dscf).

(2) Exhibit 20 percent opacity or greater.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any pneumatic coal cleaning equipment, gases which:

(1) Contain particulate matter in excess of 0.040 g/dscm (0.018 gr/dscf).

(2) Exhibit 10 percent opacity or greater.

(c) On and after the date on which the performance test required to be conducted by § 60.8 is completed, an owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

§ 60.253 Monitoring of operations.

(a) The owner or operator of any thermal dryer shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(1) A monitoring device for the measurement of the temperature of the gas stream at the exit of the thermal dryer on a continuous basis. The monitoring device is to be certified by the manufacturer to be accurate within ±3° Fahrenheit.

(2) For affected facilities that use venturi scrubber emission control equipment:

(i) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the

control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±1 inch water gage.

(ii) A monitoring device for the continuous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of design water supply pressure. The pressure sensor or tap must be located close to the water discharge point. The Administrator may be consulted for approval of alternative locations.

(b) All monitoring devices under paragraph (a) of this section are to be recalibrated annually in accordance with procedures under § 60.13(b)(3) of this part.

§ 60.254 Test methods and procedures.

(a) The reference methods in Appendix A of this part, except as provided in § 60.8(b), are used to determine compliance with the standards prescribed in § 60.252 as follows:

(1) Method 5 for the concentration of particulate matter and associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate, and

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling time for each run is at least 60 minutes and the minimum sample volume is 0.85 dscm (30 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator. Sampling is not to be started until 30 minutes after start-up and is to be terminated before shutdown procedures commence. The owner or operator of the affected facility shall eliminate cyclonic flow during performance tests in a manner acceptable to the Administrator.

(c) The owner or operator shall construct the facility so that particulate emissions from thermal dryers or pneumatic coal cleaning equipment can be accurately determined by applicable test methods and procedures under paragraph (a) of this section.

[FR Doc.76-1240 Filed 1-14-76,8:45 am]

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 452-3]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Primary Copper, Zinc, and Lead Smelters

On October 16, 1974 (39 FR 37040), pursuant to section 111 of the Clean Air Act, as amended, the Administrator proposed standards of performance for new and modified sources within three categories of stationary sources: (1) primary copper smelters, (2) primary zinc smelters, and (3) primary lead smelters. The Administrator also proposed amendments to Appendix A, Reference Methods, of 40 CFR Part 60.

Interested persons representing industry, trade associations, environmental groups, and Federal and State governments participated in the rulemaking by sending comments to the Agency. Commentators submitted 14 letters containing eighty-five comments. Each of these comments has been carefully considered and where determined by the Administrator to be appropriate, changes have been made to the proposed regulations which are promulgated herein.

The comment letters received, a summary of the comments contained in these letters, and the Agency's responses to these comments are available for public inspection at the Freedom of Information Center, Room 202 West Tower, 401 M Street, S.W., Washington, D.C. Copies of the comment summary and the Agency's responses may be obtained by writing to the EPA Public Information Center (PM-215), 401 M Street, S.W., Washington, D.C. 20460, and requesting the Public Comment Summary—Primary Copper, Zinc and Lead Smelters.

The bases for the proposed standards are presented in "Background Information for New Source Performance Standards: Primary Copper, Zinc and Lead Smelters, Volume 1, Proposed Standards" (EPA-450/2-74-002a) and "Economic Impact of New Source Performance Standards on the Primary Copper Industry: An Assessment" (EPA Contract No. 68-02-1349—Task 2). Copies of these documents are available on request from the Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention: Mr. Don R. Goodwin.

Summary of Regulations

The promulgated standards of performance for new and modified primary copper smelters limit emissions of particulate matter contained in the gases discharged into the atmosphere from dryers to 50 mg/dscm (0.022 gr/dscf). In addition, the opacity of these gases is limited to 20 percent.

Emissions of sulfur dioxide contained in the gases discharged into the atmosphere from roasters, smelting furnaces and copper converters are limited to 0.065 percent by volume (650 parts per million) averaged over a six-hour period. Reverberatory smelting furnaces at primary copper smelters which process an average smelter charge containing a high level of volatile impurities, however, are exempt from this standard during those periods when such a charge is processed. A high level of volatile impurities is defined to be more than 0.2 weight percent arsenic, 0.1 weight percent antimony, 4.5 weight percent lead or 5.5 weight percent zinc. In addition, where a sulfuric acid plant is used to comply with this standard, the opacity of the gases discharged into the atmosphere is limited to 20 percent.

The regulations also require any primary copper smelter that makes use of the exemption provided for reverberatory smelting furnaces processing a charge of high volatile impurity content to keep a monthly record of the weight percent of arsenic, antimony, lead and zinc contained in this charge. In addition, the regulations require continuous monitoring systems to monitor and record the opacity of emissions discharged into the atmosphere from any dryer subject to the standards and the concentration of sulfur dioxide in the gases discharged into the atmosphere from any roaster, smelting furnace, or copper converter subject to the standard. While these regulations pertain primarily to sulfur dioxide emissions, the Agency recognizes the potential problems posed by arsenic emissions and is conducting studies to assess these problems. Appropriate action will be taken at the conclusion of these studies.

The promulgated standards of performance for new and modified primary zinc smelters limit emissions of particulate matter contained in the gases discharged into the atmosphere from sintering machines to 50 mg/dscm (0.022 gr/dscf). The opacity of these gases is limited to 20 percent.

Emissions of sulfur dioxide contained in the gases discharged into the atmosphere from roasters and from any sintering machine which eliminates more than 10 percent of the sulfur initially contained in the zinc sulfide concentrates processed are limited to 0.065 percent by volume (650 parts per million) averaged over a two-hour period. In addition, where a sulfuric acid plant is used to comply with this standard, the opacity of the gases discharged into the atmosphere is limited to 20 percent.

The regulations also require continuous monitoring systems to monitor and record the opacity of emissions discharged into the atmosphere from any sintering machine subject to the standards, and the concentration of sulfur dioxide in the gases discharged into the atmosphere from any roasters or sintering machine subject to the standard limiting emissions of sulfur dioxide.

The promulgated standards of performance for new and modified primary lead smelters limit emissions of particulate matter contained in the gases discharged into the atmosphere from blast furnaces, dross reverberatory furnaces and sintering machine discharge ends to 50 mg/dscm (0.022 gr/dscf). The opacity of these gases is limited to 20 percent.

Emissions of sulfur dioxide contained in the gases discharged into the atmosphere from sintering machines, electric smelting furnaces and converters are limited to 0.065 percent by volume (650 parts per million) averaged over a two-hour period. Where a sulfuric acid plant is used to comply with this standard, the opacity of the gases discharged into the atmosphere is limited to 20 percent.

The regulations also require continuous monitoring systems to monitor and record the opacity of emissions discharged into the atmosphere from any blast furnace, dross reverberatory furnace, or sintering machine discharge end subject to the standards, and the concentration of sulfur dioxide in the gases discharged into the atmosphere from any sintering machine, electric furnace or converter subject to the standards.

Major Comments and Changes Made to the Proposed Standards

PRIMARY COPPER SMELTERS

Most of the comments submitted to the Agency concerned the proposed standards of performance for primary copper smelters. As noted in the preamble to the proposed standards, the domestic copper smelting industry expressed strong objections to these standards during their development. Most of the comments submitted by the industry following proposal of these standards reiterated these objections. In addition, a number of comments were submitted by State agencies, environmental organizations and private individuals, also expressing objections to various aspects of the proposed standards. Consequently, it is appropriate to review the basis of the proposed standards before discussing the comments received, the responses to these comments and the changes made to the standards for promulgation.

The proposed standards would have limited the concentration of sulfur dioxide contained in gases discharged into the atmosphere from all new and modified roasters; reverberatory, flash and electric smelting furnaces; and copper converters at primary copper smelters to 650 parts per million. Uncontrolled roasters, flash and electric smelting furnaces and copper converters discharge gas streams containing more than 3½ percent sulfur dioxide. The cost of controlling these gas streams with sulfuric acid plants was considered reasonable. Reverberatory smelting furnaces, however, normally discharge gas streams containing less than 3½ percent sulfur dioxide, and the cost of controlling these gas streams through the use of various sulfur dioxide scrubbing systems currently available was considered unreasonable in most cases. It was the Administrator's conclusion, however, that flash and electric smelting considered together were applicable to essentially the full range of domestic primary copper smelting operations. Consequently, standards were proposed which applied equally to new

flash, electric and reverberatory smelting furnaces. The result was standards which favored construction of new flash and electric smelting furnaces over new reverberatory smelting furnaces.

Most of the increase in copper production over the next few years will probably result from expansion of existing copper smelters. Of the sixteen domestic primary copper smelters, only one employs flash smelting and only two employ electric smelting. The remaining thirteen employ reverberatory smelting, although one of these thirteen has initiated construction to convert to electric smelting and another has initiated construction to convert to a new smelting process referred to as Noranda smelting. (The Noranda smelting process discharges a gas stream of high sulfur dioxide concentration which is easily controlled at reasonable costs. By virtue of the definition of a smelting furnace, the promulgated standards also apply to Noranda furnaces.)

In view of the Administrator's judgment that the cost of controlling sulfur dioxide emissions from reverberatory furnaces was unreasonable, the Administrator concluded that an exemption from the standards was necessary for existing reverberatory smelting furnaces, to permit expansion of existing smelters at reasonable costs. Consequently, the proposed standards stated that any physical changes or changes in the method of operation of existing reverberatory smelting furnaces, which resulted in an increase in sulfur dioxide emissions from these furnaces, would not cause these furnaces to be considered "modified" affected facilities subject to the standards. This exemption, however, applied only where total emissions of sulfur dioxide from the primary copper smelter in question did not increase.

Prior to the proposal of these standards, the Administrator commissioned the Arthur D. Little Co., Inc., to undertake an independent assessment of both the technical basis for the standards and the potential impact of the standards on the domestic primary copper smelting industry. The results of this study have been considered together with the comments submitted during the public review and comment period in determining whether the proposed standards should be revised for promulgation.

Briefly, the Arthur D. Little study reached the following conclusions:

(1) The proposed standards should have no adverse impact on new primary copper smelters processing materials containing low levels of volatile impurities.

(2) The proposed standards could reduce the capability of new primary copper smelters located in the southwest U.S. to process materials of high impurity content. This impact was foreseen since the capability of flash smelting to process materials of high impurity levels was unknown. Although electric smelting was considered technically capable of processing these materials, the higher costs associated with electric smelting, due to the high cost of electrical power in the southwest, were considered sufficient to preclude its use in most cases.

This conclusion was subject, however, to qualification. It applied only to the southwest (Arizona, New Mexico and west Texas) and not to other areas of the United States (Montana, Nevada, Utah and Washington) where primary copper smelters currently operate; and it was not viewed as applicable to large new ore deposits of high impurity content which were capable of providing the entire charge to a new smelter. The study also concluded it was impossible to estimate the magnitude of this potential impact since it was not possible to predict impurity levels likely to be produced from new ore reserves.

Although considerable doubt existed as to the need for a new smelter in the southwest to process materials of high impurity levels in the future (essentially all the information and data examined indicated such a need is not likely to arise), the Arthur D. Little study concluded it would be prudent to assume new smelters in the southwest should have the flexibility to process these materials. To assume otherwise according to the study might place constraints on possible future plans of the American Smelting and Refining Company.

(3) The proposed standards should have little or no impact on the ability of existing primary copper smelters to expand copper production. This conclusion was also subject to qualification. It was noted that other means of expanding smelter capacity might exist than the approaches studied and that the proposed standards might or might not influence the viability of these other means of expanding capacity. It was also noted that the study assumed existing single absorption sulfuric acid plants could be converted to double absorption, but that individual smelters were not visited and this conversion might not be possible at some smelters.

Each of the comment letters received by EPA contained multiple comments. The most significant comments, the Agency's responses to these comments and the various changes made to the proposed regulations for promulgation in response to these comments are discussed below.

(1) *Legal authority under section 111.* Four commentators indicated that the Agency would exceed its statutory authority under section 111 of the Act by promulgating a standard of performance that could not be met by copper reverberatory smelting furnaces, which are extensively used at existing domestic smelters. The commentators believe that the "best system of emission reduction" cited in section 111 refers to control techniques that reduce emissions, and not to processes that emit more easily controlled effluent gas streams. The commentators contend, therefore, that a producer may choose the process that is most appropriate in his view, and new source performance standards must be based on the application of the best demonstrated techniques of emission reduction to that process.

The legislative history of the 1970 Amendments to the Act is cited by these commentators as supporting this interpretation of section 111. Specifically pointed out is the fact that the House-Senate Conference Committee, which reconciled competing House and Senate versions of the bill, deleted language from the Senate bill that would have granted the Agency explicit authority to regulate processes. This action, according to these commentators, clearly indicates a Congressional intent not to grant the Agency such authority.

The conference bill, however, merely replaced the phrase in the Senate bill "latest available control technology, processes, operating method or other alternatives" with "best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated." The use of the phrase "best system of emission reduction" appears to be inclusive of the terms in the Senate bill. The absence of discussion in the conference report on this issue further suggests that no substantive change was intended by the substitution of the phrase "best system of emission reduction" for the phrase "latest available control technology, processes, operating method or other alternatives" in the Senate bill.

For some classes of sources, the different processes used in the production activity significantly affect the emission levels of the source and/or the technology that can be applied to control the source. For this reason, the Agency believes that the "best system of emission reduction" includes the processes utilized and does not refer only to emission control hardware. It is clear that adherence to existing process utilization could serve to undermine the purpose of section 111 to require maximum feasible control of new sources. In general, therefore, the Agency believes that section 111 authorizes the promulgation of one standard applicable to all processes used by a class of sources, in order that the standard may reflect the maximum feasible control for that class. When the application of a standard to a given process would effectively ban the process, however, a separate standard must be prescribed for it unless some other process(es) is available to perform the function at reasonable cost.

In determining whether the use of different processes would necessitate the setting of different standards, the Agency first determines whether or not the processes are functionally interchangeable. Factors such as whether the least polluting process can be used in various locations or with various raw materials or under other conditions are considered. The second important consideration of the Agency involves the costs of achieving the reduction called for by a standard applicable to all processes used in a source category. Where a single standard would effectively preclude using a process which is much less expensive than the permitted process, the economic impact of the single standard must be determined to be reasonable or separate standards are set. This does not mean, however, that the cost of the alternatives to the potentially prohibited process can

be no grater than those which would be associated with controlling the process under a less stringent standard.

The Administrator has determined that the flash copper smelting process is available and will perform the function of the reverberatory copper smelting process at reasonable cost, except that flash smelting has not yet been commercially demonstrated for the processing of feed materials with a high level of volatile impurities. The standards promulgated herein, which do not apply to copper reverberatory smelting furnaces when the smelter charge contains a high level of volatile impurities, are therefore authorized under section 111 of the Act.

(2) *Control of reverberatory smelting furnaces.* Two commentators representing environmental groups and one commentator representing a State pollution control agency questioned the Administrator's judgment that the use of various sulfur dioxide scrubbing systems to control sulfur dioxide emissions from reverberatory smelting furnaces was unreasonable, especially in view of his conclusion that the use of these systems on large steam generators was reasonable. These commentators also pointed out that this conclusion was based only on an examination of the use of sulfur dioxide scrubbing systems and that alternative means of control, such as the use of oxygen enrichment of reverberatory furnace combustion air, or the mixing of the gases from the reverberatory furnace with the gases from roasters and copper converters to produce a mixed gas stream suitable for control, were not examined.

This comment was submitted in response to the exemption included in the proposed standards for existing reverberatory smelting furnaces. As discussed below, the amendments recently promulgated by the Agency to 40 CFR Part 60 clarifying the meaning of "modification" make this exemption unnecessary. The comment is still appropriate, however, since the promulgated standards now include an exemption for new reverberatory smelting furnaces at smelters processing materials containing high levels of volatile impurities.

Section 111 of the Clean Air Act dictates that standards of performance be based on "* * * the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated." Thus, not only must various systems of emission control be investigated to ensure these systems are technically proven and the levels to which emissions could be reduced through the use of these systems identified, the costs of these systems must be considered to ensure that standards of performance will not impose an unreasonable economic burden on each source category for which standards are developed.

The control of gas streams containing low concentrations of sulfur dioxide through the use of various scrubbing systems which are currently available is considered by the Administrator to be technically proven and well demonstrated. The use of these systems on large steam generators is considered reasonable since electric utilities are regulated monopolies and the costs incurred to control sulfur dioxide emissions can be passed forward to the consumer. Primary copper smelters, however, do not enjoy a monopolistic position and face direct competition from both foreign smelters and other domestic smelters. The costs associated with the use of these scrubbing systems on reverberatory smelting furnaces at primary copper smelters are so large, in the Administrator's judgment, that they could not be either absorbed by a copper smelter without resulting in a significant decrease in profitability, passed forward to the consumer without leading to a significant loss in sales, or passed back to the mining operations without resulting in a closing of some mines and a decrease in mining activity. Consequently, the Administrator considers the use of these systems to control reverberatory smelting furnaces unreasonable.

Although little discussion is included in the background document supporting the proposed standards concerning the use of oxygen enrichment of reverberatory furnace combustion air, or the mixing of the gases from reverberatory furnaces with the gases from roasters and copper converters, these approaches for controlling sulfur dioxide emissions from reverberatory smelting furnaces were examined. These investigations, however, were not of an in-depth nature and were not pursued to completion.

A preliminary analysis of oxygen enrichment of reverberatory furnace combustion air to produce a strong gas stream from the reverberatory furnace appeared to indicate that the costs associated with this approach were unreasonable. A similar analysis of the mixing of the gases from a reverberatory furnace with the gases discharged from a fluid-bed roaster and copper converters appeared to indicate that although the costs associated with this approach were reasonable, it was not possible to use fluid-bed roasters in all cases. Multihearth roasters would be required where materials of high volatile impurity levels were processed. Although multi-hearth roasters discharge strong gas streams (4–5 percent sulfur dioxide), fluid bed roasters discharge much stronger gas streams (10–12 percent sulfur dioxide). To determine the effect of this lower concentration of sulfur dioxide in the gases discharged by multi-hearth roasters on the ability to mix the gases discharged by reverberatory smelting furnaces with those discharged by roasters and copper converters to produce a mixed gas stream suitable for control at reasonable costs would have required further investigation and study.

Unfortunately, limited resources prevented all avenues of investigation from being pursued and in view of the promising indications from the preliminary investigations into flash and electric smelting, the Agency concentrated its efforts in this area. As discussed below, however, the use of these approaches to control sulfur dioxide emissions from reverberatory smelting furnaces are under investigation as a means by which the promulgated standards of performance could be extended to cover reverberatory smelting furnaces which process materials containing high levels of impurities.

(3) *Materials of high impurity levels.* One commentator expressed his belief that the proposed standards would prevent new primary copper smelters from processing materials containing high levels of impurities, such as arsenic, antimony, lead and zinc. This commentator does not feel flash smelting can be considered demonstrated for smelting materials containing these impurities. The commentator also feels the domestic smelting industry will not be able to employ electric smelting to process materials of this nature in the future, since electric power will not be available, or only available at a price which will prevent its use by the industry.

At the time of proposal of the standards for primary copper smelters, the Administrator was aware that considerable doubt existed concerning the capability of flash smelting to process materials of high impurity levels. No doubt existed, however, with regard to the capability of electric smelting to process these materials. Consequently, the standards were proposed on the basis that where flash smelting could not be employed to process these materials, electric smelting could.

As outlined above, the Arthur D. Little study concluded that at no flash smelter in the world has the average composition of the total charge processed on a routine basis exceeded 0.2 weight percent arsenic, 0.1 weight percent antimony, 4.5 weight percent lead and 5.5 weight percent zinc. Thus, the capability of flash smelting to process a charge containing higher levels of impurities than these has not been adequately demonstrated. At this time, therefore, only electric smelting preceded by multi-hearth roasting (in addition to reverberatory smelting preceded by multi-hearth roasting) can be considered adequately demonstrated (excluding costs) for processing these materials.

The Arthur D. Little study also examined the projected availability and pricing of various forms of energy through 1980 for those areas of the United States where primary copper smelters now operate. Although the energy consumed by electric smelting is approximately equal to that consumed by reverberatory smelting (taking into account the energy inefficiency associated with electric power generation), the study concluded that a cost penalty of 1 to 2 cents per pound of copper is associated with electric smelting in the southwest U.S. due to the high cost of electric power in this region. This cost penalty was considered sufficient in the Arthur D. Little study to make the use

of electric smelting at new primary copper smelters located in the southwest economically unattractive in most cases.

Since the basis for the proposed standards considered electric smelting as a viable alternative should flash smelting prove unable to process materials of high impurity levels, the Administrator has concluded the proposed standards should be revised for promulgation. Consequently, the standards promulgated herein exempt new reverberatory smelting furnaces at primary copper smelters which process a total charge containing more than 0.2 weight percent arsenic, 0.1 weight percent antimony, 4.5 weight percent lead or 5.5 weight percent zinc. This will permit new primary copper smelters to be constructed to process materials of high impurity levels without employing electric smelting. The promulgated standards of performance will, however, apply to new roasters and copper converters at these smelters, since the Administrator has concluded these facilities can be operated to produce gas streams containing greater than 3½ percent sulfur dioxide and that the costs associated with controlling these gas streams are reasonable.

Although the Administrator considers it prudent to promulgate the standards with this exemption for new reverberatory smelting furnaces, the Administrator believes this exemption may not be necessary. As pointed out in the comments submitted by various environmental organizations and private citizens, neither the use of oxygen enrichment of reverberatory furnace combustion air, nor the mixing of the gases from reverberatory furnaces with those from multihearth roasters and copper converters were investigated in depth by the Agency in developing the proposed standards. Either of these approaches could prove to be reasonable for controlling sulfur dioxide emissions from reverberatory smelting furnaces.

Under the promulgated standards with the exemptions provided for new reverberatory smelting furnaces, new primary copper smelters could remain among the largest point sources of sulfur dioxide emissions within the U.S. Consequently, the Agency's program to develop standards of performance to limit sulfur dioxide emissions from primary copper smelters will continue. This program will focus on the use of oxygen enrichment of reverberatory furnace combustion air and the mixing of the gases from reverberatory smelting furnaces with those from multi-hearth roasters and copper converters. If the Administrator concludes either or both of these approaches can be employed to control sulfur dioxide emissions from reverberatory smelting furnaces at reasonable costs, the Administrator will propose that this exemption be deleted.

(4) *Copper smelter modifications.* One of the major issues associated with the proposed regulations on modification, notification and reconstruction (39 FR 36946) involved the "bubble concept." The "bubble concept" refers to the trading off of emission increases from one existing facility undergoing a physical or operational change at a source with emission reductions from another existing facility at the same source. If there is no net increase in the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by the source as a whole, the facility which experienced an emissions increase is not considered modified. Although the "bubble concept" may be applied to existing facilities which undergo a physical or operational change, it may not be applied to cover construction of new facilities

In commenting on the proposed standards of performance for primary copper smelters, two commentators suggested that the bubble concept be extended to include construction of new facilities at existing copper smelters. These commentators indicated that this could result in a substantial reduction in the costs, while at the same time leading to a substantial reduction in emissions from the smelter.

To support their claims, these commentators presented two hypothetical examples of expansions at a copper smelter that could occur through construction of new facilities. Where new facilities were controlled to meet standards of performance, emissions from the smelter as a whole increased. Where some new facilities were not controlled to meet standards of performance, emissions from the smelter as a whole decreased substantially.

These results, however, depend on special manipulation of emissions from the existing facilities at the smelter. In the case where new facilities are controlled to meet standards of performance, emissions from existing facilities are not reduced. Thus, with construction of new facilities, emissions from the smelter as a whole increase. In the case where some new facilities are not controlled to meet standards of performance, emissions from existing facilities are reduced through additional emission control or production cut-back. Since emissions from the existing facilities were assumed to be very large initially, a reduction in these emissions results in a net reduction in emissions from the smelter as a whole.

These hypothetical examples, however, appear to represent contrived situations. In many cases, compliance with State implementation plans to meet the National Ambient Air Quality Standards will require existing copper smelters to control emissions to such a degree that the situations portrayed in the examples presented by these commentators are not likely to arise. Furthermore, a smelter operator may petition the Administrator for reconsideration of the promulgated standards if he believes they would be infeasible when applied to his smelter.

Another commentator asked whether conversion of an existing reverberatory smelting furnace from firing natural gas to firing coal would constitute a modification. This commentator pointed out that although the conversion to firing coal would increase sulfur dioxide emissions from the smelter by 2 to 3 percent, the costs of controlling the furnace to meet the standards of performance would be prohibitive.

The primary objective of the promulgated standards is to control emissions of sulfur dioxide from the copper smelting process. The data and information supporting the standards consider essentially only those emissions arising from the basic smelting process, not those arising from fuel combustion. It is not the direct intent of these standards, therefore, to control emissions from fuel combustion per se. Consequently, since emissions from fuel combustion are negligible in comparison with those from the basic smelting process, and a conversion of reverberatory smelting furnaces to firing coal rather than natural gas will aid in efforts to conserve natural gas resources, the standards promulgated herein include a provision exempting fuel switching in reverberatory smelting furnaces from consideration as a modification.

(5) *Expansion of existing smelters.* Two commentators expressed their concern that the proposed standards would prevent the expansion of existing primary copper smelters, since the standards apply to modified facilities as well as new facilities. These commentators reasoned that the costs associated with controlling emissions from each roaster smelting furnace or copper converter modified during expansion would in many cases make these expansions economically unattractive.

As noted above, the Agency has proposed amendments to the general provisions of 40 CFR Part 60 covering modified and reconstructed sources. Under these provisions, standards of performance apply only where an existing facility at a source is reconstructed; where a change in an existing facility results in an increase in the total emissions at a source, and where a new facility is constructed at a source. Thus, unless total emissions from a primary copper smelter increase, most alterations to existing roasters, smelting furnaces or copper converters which increase their emissions will not cause these facilities to be considered modified and subject to standards of performance.

The Administrator does not believe the standards promulgated herein will deter expansion of existing primary copper smelters. As discussed earlier, the Administrator concluded at proposal that the cost of controlling reverberatory smelting furnaces was unreasonable (through the use of various sulfur dioxide scrubbing systems currently available), and for this reason included an exemption in the proposed standards for existing reverberatory smelting furnaces. The prime objective of this exemption was to ensure that existing primary copper smelters could expand copper production at reasonable costs.

Also, as discussed earlier, the Arthur D. Little study examined this aspect of the proposed standards and concluded the standards would have little or no impact on the ability of existing primary copper smelters to expand production.

This conclusion was subject to two qualifications: other means of expanding smelter capacity might exist than those examined and the impact of the proposed standards on these means of expanding capacity is unknown; and it was assumed that existing single absorption sulfuric acid plants could be converted to double absorption, but at some smelters this might not be possible.

The Administrator does not feel these qualifications seriously detract from the essential conclusion that the standards are likely to have little impact on the expansion capabilities of existing copper smelters. The various means of expanding smelter capacity examined in the Arthur D. Little study represent commonly employed techniques for increasing copper production from as little as 10 to 20 percent, to as much as 50 percent at existing smelters. Consequently, the Administrator considers the approaches examined in the study as broadly representative of various means of expanding existing primary copper smelters and as a reasonable basis from which conclusions regarding the potential impact of the standards on the expansion capabilities of the domestic primary copper smelting industry can be drawn.

The Administrator views the assumption in the Arthur D. Little report that existing single absorption sulfuric acid plants can be converted to double absorption as a good assumption. Although at some existing primary copper smelters the physical plant layout might complicate a conversion from single absorption to double absorption, the remote isolated location of most smelters provides ample space for the construction of additional plant facilities. Thus, while the costs for conversion may vary from smelter to smelter, it is unlikely that at any smelter a conversion could not be made.

As proposed, provisions were included in the regulations specifically stating that physical and operating changes to existing reverberatory smelting furnaces which resulted in an increase in sulfur dioxide emissions would not be considered modifications, provided total emissions of sulfur dioxide from the copper smelter did not increase above levels specified in State implementation plans.

Since proposal of the standards, amendments to 40 CFR Part 60 to clarify the meaning of modification under section 111 have been proposed. These amendments permit changes to existing facilities within a source which increase emissions from these facilities without requiring compliance with standards of performance, provided total emissions from the source do not increase. Since this was the objective of the provisions included in the proposed regulations for primary copper smelters with regard to changes to existing reverberatory smelting furnaces, these provisions are no longer necessary and have been deleted from the promulgated regulations.

(6) *Increased energy consumption.* Two commentators indicated that the Agency's estimate of the impact of the standards of performance for primary copper, zinc and lead smelters on energy consumption was much too low. Since the number of smelters which will be affected by the standards is relatively small, the Agency has developed a scenario on a smelter-by-smelter basis, by which the domestic industry could increase copper production by 400,000 tons by 1980. This increase in copper production represents a growth rate of about 3.5 percent per year and is consistent with historical industry growth rates of 3 to 4 percent per year.

On this new basis, the energy required to control all new primary copper, zinc and lead smelters constructed by 1980 to comply with both the proposed standards and the standards promulgated herein is the same and is estimated to be 320 million kilowatt-hours per year. This is equivalent to about 520,000 barrels of number 6 fuel oil per year. Relative to typical State implementation plan requirements for primary copper, zinc and lead smelters, the incremental energy required by these standards is 50 million kilowatt-hours per year, which is equivalent to about 80,000 barrels of number 6 fuel oil per year.

The energy required to comply with the promulgated standards at these new smelters by 1980 represents no more than approximately 3.5 percent of the process energy which would be required to operate these smelters in the absence of any control of sulfur dioxide emissions. The incremental amount of energy required to meet these standards is somewhat less than 0.5 percent of the total energy (process plus air pollution) which would be required to operate these new smelters and meet typical State implementation plan emission control requirements.

One commentator stated the Agency's initial estimate of the increased energy requirements associated with the proposed standards was low because the Agency did not take into account a 3 million Btu per ton of copper concentrate energy debit, attributed by the commentator to electric smelting compared to reverberatory smelting. The new basis used by the Agency to estimate the impact of the standards on energy consumption anticipates no new electric smelting by 1980. Consequently, any difference in the energy consumed by electric smelting compared to reverberatory smelting will have no impact on the amount of energy required to comply with the standards.

The Agency's estimates of the energy requirements associated with electric smelting and reverberatory smelting, which are included in the background information for the proposed standards, are based on a review of the technical literature and contacts with individual smelter operators. These estimates agree quite favorably with those developed in the Arthur D. Little study, which verified the Agency's conclusion that the overall energy requirements associated with reverberatory and electric smelting are essentially the same. It remains, the Administrator's conclusion, therefore, that there is no energy debit associated with electric smelting compared to reverberatory smelting.

Another commentator feels the Agency's original estimates fail to take into account the fuel necessary to maintain proper operating temperatures in sulfuric acid plants. This commentator estimates that about 82,000 barrels of fuel oil per year are required to heat the gases in a double absorption sulfuric acid plant. The commentator then assumes the domestic non-ferrous smelting industry will expand production by 50 percent in the immediate future, citing the Arthur D. Little study for support. Since about 30 metallurgical sulfuric acid plants are currently in use within the domestic smelting industry, the commentator assumes this means 15 new metallurgical sulfuric acid plants will be constructed in the future. This leads to an estimated energy impact associated with the standards of performance of about 1¼ million barrels of fuel oil per year.

It should be noted, however, that the growth projections developed in the Arthur D. Little study are only for the domestic copper smelting industry, and cannot be assumed to apply to the domestic zinc and lead smelting industries. Over half the domestic zinc smelters, for example, have shut down since 1968 and zinc production has fallen sharply, although recently plans have been announced for two new zinc smelters. In addition, the domestic lead industry is widely viewed as a static industry with little prospect for growth in the near future.

Furthermore, the Arthur D. Little study does not project a 50 percent expansion of the domestic copper smelting industry in the immediate future. By 1980, the study estimates domestic copper production will have increased by 15 percent over 1974 and by 1985, domestic copper production will have increased by 35 percent.

The Agency's growth projections for the domestic copper smelting industry are somewhat higher than those of the Arthur D. Little study and forecast a 19 percent increase in copper production by 1980 over 1974. The commentator's estimate of a 50 percent expansion of the domestic non-ferrous smelting industry in the immediate future, therefore, appears much too high. Where the commentator estimates that the standards of performance will affect the construction of 15 new metallurgical sulfuric acid plants, the Agency estimates the standards will affect the construction of 7 new acid plants (6 in the copper industry, 1 in the zinc industry and none in the lead industry). In addition, the Agency estimates the standards will require the conversion of 6 existing single absorption acid plants to double absorption (5 in the copper industry, 1 in the zinc industry and none in the lead industry).

As noted above, the commentator's calculations also assume that these 15 new metallurgical acid plants do not operate autothermally (i.e., fuel firing is necessary to maintain proper operating temperatures). The commentator's estimate that a double absorption sulfuric acid plant requires 82,000 barrels of fuel oil per year is based on operation of an acid plant designed to operate autothermally at 4½ percent sulfur dioxide, but which operates on gases con-

taining only 3½ percent sulfur dioxide 40 percent of the time.

Using this same basis, the Agency calculates that a sulfuric acid plant should require less than 5,000 barrels of oil per year. A review of these calculations with two acid plant vendors and a private consultant has disclosed no errors. The Administrator must assume, therefore, that the commentator's calculations are in error, or assume an unrealistically low degree of heat recovery in the acid plant to preheat the incoming gases, or are based on a poorly designed or poorly operated sulfuric acid plant which fails to achieve the degree of heat recovery normally expected in a properly designed and operated sulfuric acid plant.

Regardless of these calculations, however, the Administrator feels that with good design, operation and maintenance of the roasters, smelting furnaces, concerters, sulfuric acid plant and the flue gas collection system and ductwork, the concentration of sulfur dioxide in the gases processed by a sulfuric acid plant can be maintained above 3½ to 4 percent sulfur dioxide. This level is typically the autothermal point at which no fuel need be fired to maintain proper operating temperatures in a well designed metallurgical sulfuric acid plant. Except for occasional start-ups, therefore, a well designed and properly operated metallurgical sulfuric acid plant should operate autothermally and not require fuel for maintaining proper operating temperatures. Thus, it remains the Administrator's conclusion that the impact of the standards on increased energy consumption, resulting from increased fuel consumption to operate sulfuric acid plants, is negligible.

(7) *Emission control technology.* As three commentators correctly noted, the proposed standards essentially require the use of one emission control technology—double absorption sulfuric acid plants. These commentators feel, however, that this prevents the use of alternative emission control technologies such as single absorption sulfuric acid plants and elemental sulfur plants, and that these are equally effective and, in the case of elemental sulfur plants, place less stress on the environment.

Although these commentators acknowledge that double absorption sulfuric acid plants operate at a higher efficiency than single absorption acid plants (99.5 percent vs. 97 percent), they feel the availability of double absorption plants is lower than that of single absorption plants (90 percent vs. 92 percent). These commentators also point out that double absorption acid plants require more energy to operate than single absorption plants. When the effect of these factors on overall sulfur dioxide emissions is considered, these commentators feel there is no essential difference between double and single absorption acid plants.

The difference in availability between single and double absorption sulfuric acid plants cited by these commentators was estimated from data gathered solely on single absorption acid plants, and is due essentially to only one item—that of the acid coolers for the sulfuric acid produced in the absorption towers. The data used by these commentators, however, reflects "old technology" in this respect. If the data are adjusted to reflect new acid cooler technology, the availability of single and double absorption acid plants is estimated to be 94 and 93.5 percent, respectively.

Taking into account these differences in efficiency and availability, the installation of a 1000-ton-per-day double absorption acid plant rather than a single absorption acid plant results in an annual reduction in sulfur dioxide emissions of about 4,500 tons. The difference in annual availability between single and double absorption acid plants, however, does not influence short-term emissions. Over short time periods the difference in emissions between single and double absorption acid plants is a reflection only of their difference in operating efficiency. Over a 24-hour period, for example, a 1000-ton-per-day single absorption acid pant will emit about 20 tons of sulfur dioxide compared to about 3.5 tons from a double absorption acid plant. Consequently, the difference in emission control obtained through the use of double absorption rather than single absorption acid plants is significant.

The increased sulfur dioxide emissions released to the atmosphere to provide the greater energy requirements of double absorption over single absorption acid plants is also minimal. For a nominal 1000-ton-per-day sulfuric acid plant, the difference in sulfur dioxide emissions between a single absorption plant and a double absorption plant is about 16.5 tons per day as mentioned above. The sulfur dioxide emissions from the combustion of a 1.0 percent sulfur fuel oil to provide the difference in energy required, however, is of the order of magnitude of only 200 pounds per day.

As mentioned above, these commentators also feel that elemental sulfur plants are as effective as double absorption sulfuric acid plants and place less stress on the environment. Elemental sulfur plants normally achieve emission reduction efficiencies of only about 90 percent, which is significantly lower than the 99+ percent normally achieved in double absorption sulfuric acid plants. Consequently, the Administrator does not consider elemental sulfur plants nearly as effective as double absorption sulfuric acid plants.

Although elemental sulfur presents no potential water pollution problems and can be easily stored, thus remaining a possible future resource, the Administrator does not agree that production of elemental sulfur places less stress on the environment than production of sulfuric acid. At every smelter now producing sulfuric acid, an outlet for this acid has been found, either in copper leaching operations to recover copper from oxide ores, or in the traditional acid markets, such as the production of fertilizer. Thus, sulfuric acid, unlike elemental sulfur, has found use as a current resource and not required storage for use as a possible future resource.

The Administrator believes that this situation will also generally prevail in the future. If sulfuric acid must be neutralized at a specific smelter, however, this can be accomplished with proper precautions without leading to water pollution problems, as discussed in the background information supporting the proposed standards.

A major drawback associated with the production of elemental sulfur, however, is the large amount of fuel required as a reductant in the process. When compared to sulfuric acid production in double absorption sulfuric acid plants, elemental sulfur production requires from 4 to 6 times as much energy. Consequently, the Administrator is not convinced that elemental sulfur production, which releases about 20 times more sulfur dioxide into the atmosphere, yet consumes 4 to 6 times as much energy, could be considered less stressful on the environment than sulfuric acid production.

PRIMARY ZINC SMELTERS

Only one major comment was submitted to the Agency concerning the proposed standards of performance for primary zinc smelters. This comment questioned whether it would be possible in all cases to eliminate 90 percent or more of the sulfur originally present in the zinc concentrates during roasting.

Most primary zinc smelters employ either the electrolytic smelting process or the roast/sinter smelting process, both of which require a roasting operation. The roast/sinter process, however, requires a sintering operation following roasting. Sulfur not removed from the concentrates during roasting is removed during sintering. Since the amount of sulfur removed by sintering is small, the gases discharged from this operation contain a low concentration of sulfur dioxide. As discussed in the preamble to the proposed standards, the cost of controlling these emissions was judged by the Administrator to be unreasonable.

The amount of sulfur dioxide emitted from the sintering machine, however, depends on the sulfur removal achieved in the preceding roaster. To ensure a high degree of sulfur removal during roasting which will minimize sulfur dioxide emissions from the sintering machine, the sulfur dioxide standard applies to any sintering machine which eliminates more than 10 percent of the sulfur originally present in the zinc concentrates. This requires 90 percent or more of the sulfur to be eliminated during roasting, which is consistent with good operation of roasters as presently practiced at the two zinc smelters in the United States which employ the roast/sinter process.

One commentator pointed out that calcium and magnesium which are present as impurities in some zinc concentrates could combine with sulfur during roasting to form calcium and magnesium sulfates. These materials would remain in the calcine (roasted concentrate). If these sulfates were reduced in the sintering operation, this could lead to more than 10 percent of the sulfur originally present in the zinc concentrates being

emitted from the sintering machine. Under these conditions the sintering machine would be required to comply with the sulfur dioxide standard.

Although it is possible that this situation could arise, as acknowledged by the commentator himself it does not seem likely. Only a few zinc concentrates contain enough calcium and magnesium to carry as much as 10 percent of the sulfur in the concentrate over into the sintering operation, even assuming all the calcium and magnesium present combined with sulfur during the roasting operation.

In addition, a number of smelter operators contacted by the Agency indicated that it is quite possible that not all the calcium and magnesium present would combine with sulfur to form sulfates during roasting. It is equally possible, according to these operators, that not all the calcium and magnesium sulfates formed would be reduced in the sintering machine. Thus, even with those few concentrates which do contain a high level of calcium and magnesium, the extent to which calcium and magnesium might contribute to high sulfur emissions from the sintering operation is questionable.

Furthermore, these smelter operators indicated that at most zinc smelters a number of different zinc concentrates are normally blended to provide a homogeneous charge to the roasting operation. As pointed out by these operators, this effectively permits a smelter operator to reduce the amount of calcium and magnesium present in the charge by blending off the high levels of calcium and magnesium present in one zinc concentrate against the low levels present in another concentrate.

The Agency also discussed this potential problem with a number of mill operators. These operators indicated that additional milling could be employed to reduce calcium and magnesium levels in zinc concentrates. Although additional milling would entail some additional cost and probably result in a somewhat higher loss of zinc to the tailings, calcium and magnesium levels could be reduced well below the point where formation of calcium and magnesium sulfate during roasting would be of no concern.

While one may speculate that calcium and magnesium might lead to the formation of sulfates during roasting, which might in turn be reduced during sintering, the extent to which this would occur is unknown. Consequently, whether this would prevent a primary zinc smelter employing the roast/sinter process from limiting emissions from sintering to no more than 10 percent of the sulfur originally present in the zinc concentrates is questionable. The fact remains, however, that at the two primary zinc smelters currently operating in the United States which employ the roast/sinter process this has not been a problem. Furthermore, it appears that if calcium and magnesium were to present a problem in the future, a number of appropriate measures, such as additional blending of zinc concentrates or additional milling of those concentrates containing high calcium and magnesium levels, could be employed to deal with the situation. As a result, the standards of performance promulgated herein for primary zinc smelters require a sintering machine emitting more than 10 percent of the sulfur originally present in the zinc concentrates to comply with the sulfur dioxide standard for roasters.

PRIMARY LEAD SMELTERS

No major comments were submitted to the Agency concerning the proposed standards of performance for primary lead smelters. The proposed standards, therefore, are promulgated herein with only minor changes.

VISIBLE EMISSIONS

The opacity levels contained in the proposed standards to limit visible emissions have been reexamined to ensure they are consistent with the provisions promulgated by the Agency since proposal of these standards for determining compliance with visible emissions standards (39 FR 39872). These provisions specify, in part, that the opacity of visible emissions will be determined as a 6-minute average value of 24 consecutive readings taken at 15 second intervals. Reevaluation of the visible emission data on which the opacity levels in the proposed standards were based, in terms of 6-minute averages, indicates no need to change the opacity levels initially proposed. Consequently, the standards of performance are promulgated with the same opacity limits on visible emissions.

TEST METHODS

The proposed standards of performance for primary copper smelters, primary zinc smelters and primary lead smelters were accompanied by amendments to Appendix A—Reference Methods of 40 CFR Part 60. The purpose of these amendments was to add to Appendix A a new test method (Method 12) for use in determining compliance with the proposed standards of performance. Method 12 contained performance specifications for the sulfur dioxide monitors required in the proposed standards and prescribed the procedures to follow in demonstrating that a monitor met these performance specifications.

Since proposal of these standards of performance, the Administrator has proposed amendments to Subpart A—General Provisions of 40 CFR Part 60, establishing a consistent set of definitions and monitoring requirements applicable to all standards of performance. These amendments include a new appendix (Appendix B—Performance Specifications) which contains performance specifications and procedures to follow when demonstrating that a continuous monitor meets these performance specifications. A continuous monitoring system for measuring sulfur dioxide concentrations that is evaluated in accordance with the procedures contained in this appendix will be satisfactory for determining compliance with the standards promulgated herein for sulfur dioxide.

The proposed Method 12 is therefore withdrawn to prevent an unnecessary repetition of information in 40 CFR Part 60.

EFFECTIVE DATE

In accordance with section 111 of the Act, these regulations prescribing standards of performance for primary copper smelters, primary zinc smelters and primary lead smelters are effective on (date of publication) 1975 and apply to all affected facilities at these sources on which construction or modification commenced after October 16, 1974.

Dated: December 30, 1975.

JOHN QUARLES,
Acting Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. The table of sections is amended by adding subparts P, Q and R as follows:

* * * * *

Subpart P—Standards of Performance for Primary Copper Smelters

60.160 Applicability and designation of affected facility.
60.161 Definitions.
60.162 Standard for particulate matter.
60.163 Standard for sulfur dioxide.
60.164 Standard for visible emissions.
60.165 Monitoring of operations.
60.166 Test methods and procedures.

Subpart Q—Standards of Performance for Primary Zinc Smelters

60.170 Applicability and designation of affected facility.
60.171 Definitions.
60.172 Standard for particulate matter.
60.173 Standard for sulfur dioxide.
60.174 Standard for visible emissions.
60.175 Monitoring of operations.
60.176 Test methods and procedures.

Subpart R—Standards of Performance for Primary Lead Smelters

60.180 Applicability and designation of affected facility.
60.181 Definitions.
60.182 Standard for particulate matter.
60.183 Standard for sulfur dioxide.
60.184 Standard for visible emissions.
60.185 Monitoring of operations.
60.186 Test methods and procedures.

AUTHORITY: (Secs. 111, 114 and 301 of the Clean Air Act as amended (42 U.S.C. 1857c-6, 1857c-9, 1857g).)

* * * * *

2. Part 60 is amended by adding subparts P, Q and R as follows:

Subpart P—Standards of Performance for Primary Copper Smelters

§ 60.160 Applicability and designation of affected facility.

The provisions of this subpart are applicable to the following affected facilities in primary copper smelters: Dryer, roaster, smelting furnace, and copper converter.

§ 60.161 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Primary copper smelter" means any installation or any intermediate process engaged in the production of copper from copper sulfide ore concentrates through the use of pyrometallurgical techniques.

(b) "Dryer" means any facility in which a copper sulfide ore concentrate charge is heated in the presence of air to eliminate a portion of the moisture from the charge, provided less than 5 percent of the sulfur contained in the charge is eliminated in the facility.

(c) "Roaster" means any facility in which a copper sulfide ore concentrate charge is heated in the presence of air to eliminate a significant portion (5 percent or more) of the sulfur contained in the charge.

(d) "Calcine" means the solid materials produced by a roaster.

(e) "Smelting" means processing techniques for the melting of a copper sulfide ore concentrate or calcine charge leading to the formation of separate layers of molten slag, molten copper, and/or copper matte.

(f) "Smelting furnace" means any vessel in which the smelting of copper sulfide ore concentrates or calcines is performed and in which the heat necessary for smelting is provided by an electric current, rapid oxidation of a portion of the sulfur contained in the concentrate as it passes through an oxidizing atmosphere, or the combustion of a fossil fuel.

(g) "Copper converter" means any vessel to which copper matte is charged and oxidized to copper.

(h) "Sulfuric acid plant" means any facility producing sulfuric acid by the contact process.

(i) "Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

(j) "Reverberatory smelting furnace" means any vessel in which the smelting of copper sulfide ore concentrates or calcines is performed and in which the heat necessary for smelting is provided primarily by combustion of a fossil fuel.

(k) "Total smelter charge" means the weight (dry basis) of all copper sulfides ore concentrates processed at a primary copper smelter, plus the weight of all other solid materials introduced into the roasters and smelting furnaces at a primary copper smelter, except calcine, over a one-month period.

(l) "High level of volatile impurities" means a total smelter charge containing more than 0.2 weight percent arsenic, 0.1 weight percent antimony, 4.5 weight percent lead or 5.5 weight percent zinc, on a dry basis.

§ 60.162 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any dryer any gases which contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

§ 60.163 Standard for sulfur dioxide.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any roaster, smelting furnace, or copper converter any gases which contain sulfur dioxide in excess of 0.065 percent by volume, except as provided in paragraphs (b) and (c) of this section.

(b) Reverberatory smelting furnaces shall be exempted from paragraph (a) of this section during periods when the total smelter charge at the primary copper smelter contains a high level of volatile impurities.

(c) A change in the fuel combusted in a reverberatory furnace shall not be considered a modification under this part.

§ 60.164 Standard for visible emissions.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any dryer any visible emissions which exhibit greater than 20 percent opacity.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility that uses a sulfuric acid to comply with the standard set forth in § 60.163, any visible emissions which exhibit greater than 20 percent opacity.

§ 60.165 Monitoring of operations.

(a) The owner or operator of any primary copper smelter subject to § 60.163 (b) shall keep a monthly record of the total smelter charge and the weight percent (dry basis) of arsenic, antimony, lead and zinc contained in this charge. The analytical methods and procedures employed to determine the weight of the monthly smelter charge and the weight percent of arsenic, antimony, lead and zinc shall be approved by the Administrator and shall be accurate to within plus or minus ten percent.

(b) The owner or operator of any primary copper smelter subject to the provisions of this subpart shall install and operate:

(1) A continuous monitoring system to monitor and record the opacity of gases discharged into the atmosphere from any dryer. The span of this system shall be set at 80 to 100 percent opacity.

(2) A continuous monitoring system to monitor and record sulfur dioxide emissions discharged into the atmosphere from any roaster, smelting furnace or copper converter subject to § 60.163 (a). The span of this system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(i) The continuous monitoring system performance evaluation required under § 60.13(c) shall be completed prior to the initial performance test required under § 60.8. During the performance evaluation, the span of the continuous monitoring system may be set at a sulfur dioxide concentration of 0.15 percent by volume if necessary to maintain the system output between 20 percent and 90 percent of full scale. Upon completion of the continuous monitoring system performance evaluation, the span of the continuous monitoring system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(ii) For the purpose of the continuous monitoring system performance evaluation required under § 60.13(c) the reference method referred to under the Field Test for Accuracy (Relative) in Performance Specification 2 of Appendix B to this part shall be Reference Method 6. For the performance evaluation, each concentration measurement shall be of one hour duration. The pollutant gas used to prepare the calibration gas mixtures required under paragraph 2.1, Performance Specification 2 of Appendix B, and for calibration checks under § 60.13 (d), shall be sulfur dioxide.

(c) Six-hour average sulfur dioxide concentrations shall be calculated and recorded daily for the four consecutive 6-hour periods of each operating day. Each six-hour average shall be determined as the arithmetic mean of the appropriate six contiguous one-hour average sulfur dioxide concentrations provided by the continuous monitoring system installed under paragraph (b) of this section.

(d) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Opacity. Any six-minute period during which the average opacity, as measured by the continuous monitoring system installed under paragraph (b) of this section, exceeds the standard under § 60.164(a).

(2) Sulfur dioxide. Any six-hour period, as described in paragraph (c) of this section, during which the average emissions of sulfur dioxide, as measured by the continuous monitoring system installed under paragraph (b) of this section, exceeds the standard under § 60.163.

§ 60.166 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in §§ 60.162, 60.163 and 60.164 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content.

(2) Sulfur dioxide concentrations shall be determined using the continuous monitoring system installed in accordance with § 60.165(b). One 6-hour average period shall constitute one run. The monitoring system drift during any run shall not exceed 2 percent of span.

(b) For Method 5, Method 1 shall be used for selecting the sampling site and the number of traverse points, Method 2 for determining velocity and volumetric flow rate and Method 3 for determining the gas analysis. The sampling time for each run shall be at least 60 minutes and the minimum sampling volume shall be 0.85 dscm (30 dscf) except that smaller times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

Subpart Q—Standards of Performance for Primary Zinc Smelters

§ 60.170 Applicability and designation of affected facility.

The provisions of this subpart are applicable to the following affected facilities in primary zinc smelters: roaster and sintering machine.

§ 60.171 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Primary zinc smelter" means any installation engaged in the production, or any intermediate process in the production, of zinc or zinc oxide from zinc sulfide ore concentrates through the use of pyrometallurgical techniques.

(b) "Roaster" means any facility in which a zinc sulfide ore concentrate charge is heated in the presence of air to eliminate a significant portion (more than 10 percent) of the sulfur contained in the charge.

(c) "Sintering machine" means any furnace in which calcines are heated in the presence of air to agglomerate the calcines into a hard porous mass called "sinter."

(d) "Sulfuric acid plant" means any facility producing sulfuric acid by the contact process.

§ 60.172 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any sintering machine any gases which contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

§ 60.173 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any roaster any gases which contain sulfur dioxide in excess of 0.065 percent by volume.

(b) Any sintering machine which eliminates more than 10 percent of the sulfur initially contained in the zinc sulfide ore concentrates will be considered as a roaster under paragraph (a) of this section.

§ 60.174 Standard for visible emissions.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any sintering machine any visible emissions which exhibit greater than 20 percent opacity.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility that uses a sulfuric acid plant to comply with the standard set forth in § 60.173, any visible emissions which exhibit greater than 20 percent opacity.

§ 60.175 Monitoring of operations.

(a) The owner or operator of any primary zinc smelter subject to the provisions of this subpart shall install and operate:

(1) A continuous monitoring system to monitor and record the opacity of gases discharged into the atmosphere from any sintering machine. The span of this system shall be set at 80 to 100 percent opacity.

(2) A continuous monitoring system to monitor and record sulfur dioxide emissions discharged into the atmosphere from any roaster subject to § 60.173. The span of this system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(i) The continuous monitoring system performance evaluation required under § 60.13(c) shall be completed prior to the initial performance test required under § 60.8. During the performance evaluation, the span of the continuous monitoring system may be set at a sulfur dioxide concentration of 0.15 percent by volume if necessary to maintain the system output between 20 percent and 90 percent of full scale. Upon completion of the continuous monitoring system performance evaluation, the span of the continuous monitoring system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(ii) For the purpose of the continuous monitoring system performance evaluation required under § 60.13(c), the reference method referred to under the Field Test for Accuracy (Relative) in Performance Specification 2 of Appendix B to this part shall be Reference Method 6. For the performance evaluation, each concentration measurement shall be of one hour duration. The pollutant gas used to prepare the calibration gas mixtures required under paragraph 2.1, Performance Specification 2 of Appendix B, and for calibration checks under § 60.13 (d), shall be sulfur dioxide.

(b) Two-hour average sulfur dioxide concentrations shall be calculated and recorded daily for the twelve consecutive 2-hour periods of each operating day. Each two-hour average shall be determined as the arithmetic mean of the appropriate two contiguous one-hour average sulfur dioxide concentrations provided by the continuous monitoring system installed under paragraph (a) of this section.

(c) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Opacity. Any six-minute period during which the average opacity, as measured by the continuous monitoring system installed under paragraph (a) of this section, exceeds the standard under § 60.174(a).

(2) Sulfur dioxide. Any two-hour period, as described in paragraph (b) of this section, during which the average emissions of sulfur dioxide, as measured by the continuous monitoring system installed under paragraph (a) of this section, exceeds the standard under § 60.173.

§ 60.176 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in §§ 60.172, 60.173 and 60.174 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content.

(2) Sulfur dioxide concentrations shall be determined using the continuous monitoring system installed in accordance with § 60.175(a). One 2-hour average period shall constitute one run.

(b) For Method 5, Method 1 shall be used for selecting the sampling site and the number of traverse points, Method 2 for determining velocity and volumetric flow rate and Method 3 for determining the gas analysis. The sampling time for each run shall be at least 60 minutes and the minimum sampling volume shall be 0.85 dscm (30 dscf) except that smaller times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

Subpart R—Standards of Performance for Primary Lead Smelters

§ 60.180 Applicability and designation of affected facility.

The provisions of this subpart are applicable to the following affected facilities in primary lead smelters: sintering machine, sintering machine discharge end, blast furnace, dross reverberatory furnace, electric smelting furnace, and converter.

§ 60.181 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Primary lead smelter" means any installation or any intermediate process engaged in the production of lead from lead sulfide ore concentrates through the use of pyrometallurgical techniques.

(b) "Sintering machine" means any furnace in which a lead sulfide ore concentrate charge is heated in the presence of air to eliminate sulfur contained in the charge and to agglomerate the charge into a hard porous mass called "sinter."

(c) "Sinter bed" means the lead sulfide ore concentrate charge within a sintering machine.

(d) "Sintering machine discharge end" means any apparatus which receives sinter as it is discharged from the conveying grate of a sintering machine.

(e) "Blast furnace" means any reduction furnace to which sinter is charged and which forms separate layers of molten slag and lead bullion.

(f) "Dross reverberatory furnace" means any furnace used for the removal or refining of impurities from lead bullion.

(g) "Electric smelting furnace" means any furnace in which the heat necessary for smelting of the lead sulfide ore con-

centrate charge is generated by passing an electric current through a portion of the molten mass in the furnace.

(h) "Converter" means any vessel to which lead concentrate or bullion is charged and refined.

(i) "Sulfuric acid plant" means any facility producing sulfuric acid by the contact process.

§ 60.182 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any blast furnace, dross reverberatory furnace, or sintering machine discharge end any gases which contain particulate matter in excess of 59 mg/dscm (0.022 gr/dscf).

§ 60.183 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any sintering machine, electric smelting furnace, or converter gases which contain sulfur dioxide in excess of 0.065 percent by volume.

§ 60.184 Standard for visible emissions.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any blast furnace, dross reverberatory furnace, or sintering machine discharge end any visible emissions which exhibit greater than 20 percent opacity.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility that uses a sulfuric acid plant to comply with the standard set forth in § 60.183, any visible emissions which exhibit greater than 20 percent opacity.

§ 60.185 Monitoring of operations.

(a) The owner or operator of any primary lead smelter subject to the provisions of this subpart shall install and operate:

(1) A continuous monitoring system to monitor and record the opacity of gases discharged into the atmosphere from any blast furnace, dross reverberatory furnace, or sintering machine discharge end. The span of this system shall be set at 80 to 100 percent opacity.

(2) A continuous monitoring system to monitor and record sulfur dioxide emissions discharged into the atmosphere from any sintering machine, electric furnace or converter subject to § 60.183. The span of this system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(i) The continuous monitoring system performance evaluation required under § 60.13(c) shall be completed prior to the initial performance test required under § 60.8. During the performance evaluation, the span of the continuous monitoring system may be set at a sulfur dioxide concentration of 0.15 percent by volume if necessary to maintain the system output between 20 percent and 90 percent of full scale. Upon completion of the continuous monitoring system performance evaluation, the span of the continuous monitoring system shall be set at a sulfur dioxide concentration of 0.20 percent by volume.

(ii) For the purpose of the continuous monitoring system performance evaluation required under § 60.13(c), the reference method referred to under the Field Test for Accuracy (Relative) in Performance Specification 2 of Appendix B to this part shall be Reference Method 6. For the performance evaluation, each concentration measurement shall be of one hour duration. The pollutant gases used to prepare the calibration gas mixtures required under paragraph 2.1, Performance Specification 2 of Appendix B, and for calibration checks under § 60.13 (d), shall be sulfur dioxide.

(b) Two-hour average sulfur dioxide concentrations shall be calculated and recorded daily for the twelve consecutive two-hour periods of each operating day. Each two-hour average shall be determined as the arithmetic mean of the appropriate two contiguous one-hour average sulfur dioxide concentrations provided by the continuous monitoring system installed under paragraph (a) of this section.

(c) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Opacity. Any six-minute period during which the average opacity, as measured by the continuous monitoring system installed under paragraph (a) of this section, exceeds the standard under § 60.184(a).

(2) Sulfur dioxide. Any two-hour period, as described in paragraph (b) of this section, during which the average emissions of sulfur dioxide, as measured by the continuous monitoring system installed under paragraph (a) of this section, exceeds the standard under § 60.183.

§ 60.186 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in §§ 60.182, 60.183 and 60.184 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content.

(2) Sulfur dioxide concentrations shall be determined using the continuous monitoring system installed in accordance with § 60.185(a). One 2-hour average period shall constitute one run.

(b) For Method 5, Method 1 shall be used for selecting the sampling site and the number of traverse points, Method 2 for determining velocity and volumetric flow rate and Method 3 for determining the gas analysis. The sampling time for each run shall be at least 60 minutes and the minimum sampling volume shall be 0.85 dscm (30 dscf) except that smaller times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

[FR Doc.76-733 Filed 1-14-76;8:45 am]

27 Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 471-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Primary Aluminum Industry

On October 23, 1974 (39 FR 37730), under sections 111 and 114 of the Clean Air Act (42 U.S.C 1857c-6, 1857c-9), as amended, the Administrator proposed standards of performance for new and modified primary aluminum reduction plants. Interested persons participated in the rulemaking by submitting written comments to EPA The comments have been carefully considered and, where determined by the Administrator to be appropriate, changes have been made in the regulations as promulgated.

These regulations will not, in themselves, require control of emissions from existing primary aluminum reduction plants Such control will be required only after EPA establishes emission guidelines for existing plants under section 111(d) of the Clean Air Act, which will trigger the adoption of State emission standards for existing plants General regulations concerning control of existing sources under section 111(d) were proposed on October 7, 1975 (39 FR 36102) and were promulgated on November 17, 1975 (40 FR 53339).

The bases for the proposed standards are presented in the first two volumes of a background document entitled "Background Information for Standards of Performance: Primary Aluminum Industry" Volume 1 (EPA 450/2-74-020a, October 1974) contains the rationale for the proposed standards and Volume 2 (EPA 450/2-74-020b, October 1974) contains a summary of the supporting test data. An inflation impact statement for the standards and a summary of the comments received on the proposed standards along with the Agency responses are contained in a new Volume 3 (EPA 450/2-74-020c, November 1975) of the background document Copies of all three volumes of the background documents are available on request from the Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C 27711, Attention: Mr. Don R Goodwin.

Summary of Regulations

The standards of performance promulgated herein limit emissions of gaseous and particulate fluorides from new and modified affected facilities within primary aluminum reduction plants. The standard for fluorides limits emissions from each potroom group within Soderberg plants to 2.0 pounds of total fluorides per ton of aluminum produced (lb TF/TAP), from each potroom group within prebake plants to 1.9 lb TF/TAP, and from each anode bake plant within prebake plants to 0.1 lb TF/TAP. Primary and secondary emission from potroom groups are limited to less than 10 percent opacity, and emissions from anode bake plants are limited to less than 20 percent opacity The regulations require monitoring of raw material feed rates, cell or potline voltages, and daily production rate of aluminum and anodes. Also included with the standards is Reference Method 14 which specifies equipment and sampling procedures for emission testing of potroom roof monitors. Fluoride samples collected during performance tests will be analyzed according to Reference Method 13A or 13B which were promulgated along with standards of performance for the phosphate fertilizer industry on August 6, 1975 (40 FR 33152).

Significant Comments and Changes Made to the Proposed Regulations

Most of the comment letters received by EPA contained multiple comments Copies of the comment letters received and a summary of the comments and Agency responses are available for public inspection and copying at the U S. Environmental Protection Agency, Public Information Reference Unit, Room 2922 (EPA Library), 401 M Street, S.W., Washington, D C 20460. In addition, copies of the issue summary and Agency responses may be obtained upon written request from the EPA Public Information Center (PM-215), 401 M Street, SW., Washington, D C. 20460 [specify "Background Information for Standards of Performance: Primary Aluminum Industry Volume 3: Supplemental Information" (EPA 45/2-74-020c)]. The most significant comments and changes made to the proposed regulations are discussed below.

(1) *Designation of Affected Facility.* Several comments questioned the "applicability and designation of affected facility" section of the proposed regulations (§ 60.190) in view of regulations previously proposed by EPA with regard to modification of existing plants (39 FR 36946, October 15, 1974) In § 60 199 as proposed, the entire primary aluminum reduction plant was designated as the affected facility. The commentators argued that, as a result of this designation, addition or modification of a single potroom at an existing plant would subject all existing potrooms at the plant to the standards for new sources. The commentators argued that this situation would unfairly restrict expansion The Agency considered these comments and agreed that there would be an adverse economic impact on expansion of existing plants unless the affected facility designation were revised.

To alleviate the problem, a new affected facility designation has been incorporated in § 60.190(a) The affected facilities within primary aluminum plants are now each "potroom group" and each anode bake plant within prebake plants. This redesignation in turn required splitting the fluoride standard for prebake plants into separate standards for potroom groups and anode bake plants (see discussion in next section). As defined in § 60 191(d), the term "potroom group" means an uncontrolled potroom, or a potroom which is controlled individually, or a group of potrooms ducted to the same control system Under this revised designation, addition or modification of a potroom group at an existing plant will not subject the entire plant to the standards (unless the plant consists of only one potroom group). Similarly, addition or modification of an anode bake plant at an exiting prebake facility will not subject the entire prebake facility to the standards. Only the new or modified potroom group or anode bake plant must meet the applicable standards in such cases.

(2) *Fluoride Standard.* Many commentators questioned the level of the proposed standard; i.e., 2.0 lb TF/TAP. A number of industrial commentators suggested that the standard be relaxed or that it be specified in terms of a monthly or yearly emission limit Some commentators argued that the test data did not support the standard and that statistical techniques should have been applied to the test data in order to arrive at an emission standard.

Standards of performance under section 111 are based on the best control technology which (taking into account control costs) has been "adequately demonstrated." "Adequately demonstrated" means that the Administrator must determine, on the basis of all information available to him (including but not limited to tests and observations of existing plants and demonstration projects or pilot applications) and the exercise of sound engineering judgment, that the control technology relied upon in setting a standard of performance can be made available and will be effective to enable sources to comply with the standards In other words, test data for existing plants are not the only bases for standard setting. As discussed in the background document, EPA considered not only test data for existing plants, but also the expected performance of newly constructed plants Some existing plants tested did average less than 2.0 lb TF/TAP. Additionally, EPA believes new plants can be specifically designed for best control of air pollutants and, therefore, that new plant emission control performance should exceed that of well-controlled existing plants Finally, relatively simple changes in current operating methods (e g., cell tapping) can produce significant reductions in emissions For these reasons, EPA believes the 2.0 lb TF/TAP standard is both reasonable and achievable A more detailed discussion of the rationale for selecting the 2.0 lb TF/TAP standard is contained in Volume 1 of the background document, and EPA's responses to specific comments on the fluoride standard are contained in Volume 3

As a result of the revised affected facility designation, the 2.0 lb TF/TAP standard for prebake plants has been split into separate standards for potroom groups (1 9 lb TF/TAP) and anode bake plants (0.1 lb TF/TAP). The proposed 2 0 lb TF/TAP limitation for prebake plants always consisted of these two components, but was published as a com-

bined standard to be consistent with the original affected facility designation (i.e, the entire primary aluminum plant). At the time of proposal, the Agency had not foreseen the potential problems with modification of a two part affected facility. Data supporting each component of the standard as proposed is contained in the background document (Volumes 1 and 2). In support of the potroom component of the standard, for example, two existing prebake potrooms tested by the Agency averaged less than 1.9 lb TF/TAP. Because no well controlled anode bake plants existed at the time of aluminum plant testing, the components for anode bake plants was based on a conservatively assumed control efficiency for technology demonstrated in the phosphate fertilizer industry. Using the highest emission rate observed at two anode bake plants which were not controlled for fluorides and applying the assumed control efficiency, it was projected that these plants would emit approximately 0.06 lb TF/TAP (0.12 lb TF/ton of carbon anodes produced). In addition, as indicated in Volume 1 of the background document, it may be possible to meet the standard for anode bake plants simply by better cleaning of anode remnants. The Agency also has estimates of emission rates for a prebake facility to be built in the near future. The estimates indicate that the anode bake plant at the facility will easily meet the 0.1 TF/TAP standard.

One commentator questioned why the standard was not more stringent considering the fact that Oregon has promulgated the following standards for new primary aluminum plants: (a) a monthly average of 1.3 pounds of fluoride ion per ton of aluminum produced, and (b) an annual average of 1.0 pound of fluoride ion per ton of aluminum produced.

There are several reasons why the Agency elected not to adopt standards equivalent to the Oregon standards. Perhaps most important, EPA believes that the Oregon standards would require the installation of relatively inefficient secondary scrubbing systems at most if not all new primary aluminum plants By contrast, EPA's standard will require use of secondary control systems only for vertical stud Soderberg (VSS) plants (which are unlikely to be built in any event) and side-work prebake plants. A standard requiring secondary control systems on most if not all plants would have a substantial adverse economic impact on the aluminum industry, as is indicated in the economic section of the background document. Accordingly, EPA has concluded that considerations of cost preclude establishing a standard comparable to the Oregon standards.

A second reason for not adopting standards equivalent to the Oregon standards stems from the fact that the latter were based on test data consisting of six monthly averages (calculated by averaging from three to nine individual tests each month) from a certain well controlled plant (which incorporates both primary and secondary control). Oregon applied a statistical method to these data to derive the emission standards it adopted. As discussed in the comment summary, EPA also performed a statistical analysis of the Oregon test data, which yielded results different from those presented in the Oregon technical report. If the Agency's results had been used, less stringent emission standards might have been promulgated in Oregon.

A third consideration is that the test methods used by Oregon were not the same as those used by the Agency to collect emission data in support of the respective standards. Therefore, Oregon's test data and the Agency's test data are not directly comparable

Finally, a comment on the standard for fluorides questioned whether or not EPA had considered a new, potentially non-polluting primary aluminum reduction process developed by Alcoa. The commentator argued that if the process had become commercially available, the standard should be set at a level sufficiently stringent to stimulate the development of this new process. In response to this comment, EPA has investigated the process and has determined that it is not yet commercially available. Alcoa plans to test the process at a small pilot plant which will begin production early next year. If the pilot plant performs successfully, it will be expanded to full design capacity by the early 1980's. EPA will monitor the progress of this process and other processes under development and will reevaluate the standards of performance for the primary aluminum industry, as appropriate, in light of the new technology.

(3) *Opacity.* Some of the industrial commentators objected to the proposed opacity standards for potrooms and anode bake plants. They argued that good control of total fluorides will result in good control of particulate matter, and therefore that the opacity standards are unnecessary. EPA agrees that good control of total fluorides will result in good control of particulate matter; however, the opacity standards are intended to serve as inexpensive enforcement tools that will help to insure proper operation and maintenance of the air pollution control equipment. Under 40 CFR 60.11(d), owners and operators of affected facilities are required to operate and maintain their control equipment properly at all times Continuous monitoring instruments are often required to indicate compliance with 60.11(d), but this is not possible in the primary aluminum industry because continuous total fluoride monitors are not commercially available. The data presented in the background document indicate that the opacity standards can be easily met at well controlled plants that are properly operated and maintained. For these reasons, the opacity standards have been retained in the final regulations.

EPA recognizes, however, that in unusual circumstances (e.g., where emissions exit from an extremely wide stack) a source might meet the mass emission limit but fail to meet the opacity limit. In such cases, the owner or operator of the source may petition the Administrator to establish a separate opacity standard under 40 CFR 60 11(e) as revised on November 12, 1974 (39 FR 39872).

(4) *Control of Other Pollutants.* One commentator was concerned that EPA did not propose standards for carbon monoxide (CO) and sulfur dioxide (SO_2) emissions from aluminum plants. The commentator argued that aluminum smelters are significant sources of these pollutants, and that although fluorides are the most toxic aluminum plant emissions, standards for all pollutants should have been proposed. As discussed in the preface to Volume 1 of the background document, fluoride control was selected as one area of emphasis to be considered in implementing the Clean Air Act. In turn, primary aluminum plants were identified as major sources of fluoride emissions and were accordingly listed as a category of sources for which standards of performance would be proposed. Naturally, the initial investigation into standards for the primary aluminum industry focused on fluoride control. However, limited testing of CO and SO_2 emissions was also carried out and it was determined (a) that although primary aluminum plants might be a significant source of SO_2, SO_2 control technology had not been demonstrated in the industry, and (b) that CO emissions from such plants were insignificant. For these reasons, standards of performance were not proposed for SO_2 and CO emissions.

It is possible that SO_2 control technology used in other industries might be applicable to aluminum plants, and recent information indicates that CO emissions from such plants may be significant. At present, however, EPA has insufficient data on which to base SO_2 and CO emission standards for aluminum plants. EPA will consider the factors mentioned above and other relevant information in assigning priorities for future standard setting and invites submission of pertinent information by any interested parties Thus, standards for CO and SO_2 emissions from primary aluminum plants may be set in the future.

(5) *Reference Methods 13A and 13B.* These methods prescribe sampling and analysis procedures for fluoride emissions and are applicable to the testing of phosphate fertilizer plants in addition to primary aluminum plants. The methods were originally proposed with the primary aluminum regulations but have been promulgated with the standards of performance for the phosphate fertilizer industry (published August 6, 1975, 40 FR 33152) because the fertilizer regulations were promulgated before those for primary aluminum. Comments on the methods were received from both industries and mainly concerned possible changes in procedures and equipment specifications. As discussed in the preamble to the phosphate fertilizer regulations, some minor changes were made as a result of these comments.

Some commentators expressed a desire to replace Methods 13A and 13B with totally different methods of analysis They felt that they should not be restricted to using only those methods published by the Agency. In response to these

comments, an equivalent or alternative method may be used if approved by the Administrator under 40 CFR 60.8(b) as revised on March 8, 1974 (39 FR 9308).

(6) *Reference Method 14.* Reference Method 14 specifies sampling equipment and sampling procedures for measuring fluoride emissions from roof monitors. Most comments concerning this method suggested changes in the prescribed manifold system. A number of commentators objected to the requirement that stainless steel be used as the structural material for the manifold and suggested that other, less expensive structural materials would work as well. Data submitted by one aluminum manufacturer supported the use of aluminum for manifold construction. The Agency reviewed these data and concluded that an aluminum manifold will provide satisfactory fluoride samples if the manifold is conditioned prior to testing by passing fluoride-laden air through the system. By using aluminum instead of stainless steel, the cost of installing a sampling manifold would be substantially reduced. Since the Agency had no data on other possible structural materials, it was not possible to endorse their use in the method. However, the following wording addressing this subject has been added to the method text (§ 2.2.1): "Other materials of construction may be used if it is demonstrated through comparative testing that there is no loss of fluorides in the system."

Some commentators also objected to the requirement that the mean velocity measured during fluoride sampling be within ±10 percent of the previous 24-hour average velocity recorded through the system. In order to reduce the number of rejected sampling runs due to failure to meet the above criteria, the requirement has been amended such that the mean sampling velocity must be within ±20 percent of the previous 24-hour average velocity. EPA believes that the relaxation of this requirement will not compromise the accuracy of the method.

(7) *Economic Impact.* Some comments raised questions regarding the economic impact of the proposed regulations. The Agency has considered these comments and responded to them in the comment summary cited above. As indicated previously, an analysis of the inflationary and energy impacts of the standards appears in Volume 3 of the background document. Copies of these documents may be obtained as indicated previously.

Effective date. In accordance with section 111 of the Act, these regulations are effective January 26, 1976 and apply to sources the construction or modification of which commenced after proposal of the standards; i.e., after October 23, 1974.

(It is hereby certified that the economic and inflationary impacts of this regulation have been carefully evaluated in accordance with Executive Order 11821.)

Dated: January 19, 1976.

RUSSELL E. TRAIN,
Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations, is amended as follows:

1. The table of sections is amended by adding a list of sections for Subpart S and by adding Reference Method 14 to the list of reference methods in Appendix A as follows:

Subpart S—Standards of Performance for Primary Aluminum Reduction Plants

Sec
60.190 Applicability and designation of affected facility.
60.191 Definitions.
60.192 Standard for fluorides.
60.193 Standard for visible emissions.
60.194 Monitoring of operations.
60.195 Test methods and procedures.

* * * * *

APPENDIX A—REFERENCE METHODS

* * * * *

METHOD 14—DETERMINATION OF FLUORIDE EMISSIONS FROM POTROOM ROOF MONITORS OF PRIMARY ALUMINUM PLANTS

AUTHORITY: Secs. 111 and 114, Clean Air Act, as amended by sec. 4(a), Pub. L. 91-604, 84 Stat. 1678, 42 U.S.C. 1857 C-6, C-9.

2. Part 60 is amended by adding subpart S as follows:

Subpart S—Standards of Performance for Primary Aluminum Reduction Plants

§ 60.190 Applicability and designation of affected facility.

The affected facilities in primary aluminum reduction plants to which this subpart applies are potroom groups and anode bake plants.

§ 60.191 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Primary aluminum reduction plant" means any facility manufacturing aluminum by electrolytic reduction.

(b) "Anode bake plant" means a facility which produces carbon anodes for use in a primary aluminum reduction plant.

(c) "Potroom" means a building unit which houses a group of electrolytic cells in which aluminum is produced.

(d) "Potroom group" means an uncontrolled potroom, a potroom which is controlled individually, or a group of potrooms ducted to the same control system.

(e) "Roof monitor" means that portion of the roof of a potroom where gases not captured at the cell exit from the potroom.

(f) "Aluminum equivalent" means an amount of aluminum which can be produced from a ton of anodes produced by an anode bake plant as determined by § 60.195(e).

(g) "Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.195 or by equivalent or alternative methods [see § 60.8(b)].

(h) "Primary control system" means an air pollution control system designed to remove gaseous and particulate fluorides from exhaust gases which are captured at the cell.

(i) "Secondary control system" means an air pollution control system designed to remove gaseous and particulate fluorides from gases which escape capture by the primary control system.

§ 60.192 Standard for fluorides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain total fluorides in excess of:

(1) 1 kg/metric ton (2 lb/ton) of aluminum produced for vertical stud Soderberg and horizontal stud Soderberg plants;

(2) 0.95 kg/metric ton (1.9 lb/ton) of aluminum produced for potroom groups at prebake plants; and

(3) 0.05 kg/metric ton (0.1 lb/ton) of aluminum equivalent for anode bake plants.

§ 60.193 Standard for visible emissions.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any potroom group any gases which exhibit 10 percent opacity or greater, or

(2) From any anode bake plant any gases which exhibit 20 percent opacity or greater.

§ 60.194 Monitoring of operations.

(a) The owner or operator of any affected facility subject to the provisions of this subpart shall install, calibrate, maintain, and operate monitoring devices which can be used to determine daily the weight of aluminum and anode produced. The weighing devices shall have an accuracy of ±5 percent over their operating range.

(b) The owner or operator of any affected facility shall maintain a record of daily production rates of aluminum and anodes, raw material feed rates, and cell or potline voltages.

§ 60.195 Test methods and procedures.

(a) Except as provided in § 60.8(b), reference methods specified in Appendix A of this part shall be used to determine compliance with the standards prescribed in § 60.192 as follows:

(1) For sampling emissions from stacks:

(i) Method 13A or 13B for the concentration of total fluorides and the associated moisture content,

(ii) Method 1 for sample and velocity traverses,

(iii) Method 2 for velocity and volumetric flow rate, and

(iv) Method 3 for gas analysis.

(2) For sampling emissions from roof monitors not employing stacks or pollutant collection systems:

(i) Method 14 for the concentration of total fluorides and associated moisture content,

(ii) Method 1 for sample and velocity traverses,

(iii) Method 2 and Method 14 for velocity and volumetric flow rate, and

(iv) Method 3 for gas analysis.

(3) For sampling emissions from roof monitors not employing stacks but equipped with pollutant collection systems, the procedures under § 60.8(b) shall be followed.

(b) For Method 13A or 13B, the sampling time for each run shall be at least eight hours for any potroom sample and at least four hours for any anode bake plant sample, and the minimum sample volume shall be 6.8 dscm (240 dscf) for any potroom sample and 3.4 dscm (120 dscf) for any anode bake plant sample except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) The air pollution control system for each affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined using applicable methods specified under paragraph (a) of this section.

(d) The rate of aluminum production shall be determined as follows:

(1) Determine the weight of aluminum in metric tons produced during a period from the last tap before a run starts until the first tap after the run ends using a monitoring device which meets the requirements of § 60.194(a).

(2) Divide the weight of aluminum produced by the length of the period in hours.

(e) For anode bake plants, the aluminum equivalent for anodes produced shall be determined as follows:

(1) Determine the average weight (metric tons) of anode produced in the anode bake plant during a representative oven cycle using a monitoring device which meets the requirements of § 60.194(a).

(2) Determine the average rate of anode production by dividing the total weight of anodes produced during the representative oven cycle by the length of the cycle in hours.

(3) Calculate the aluminum equivalent for anodes produced by multiplying the average rate of anode production by two. (Note: an owner or operator may establish a different multiplication factor by submitting production records of the tons of aluminum produced and the concurrent tons of anode consumed by potrooms.)

(f) For each run, potroom group emissions expressed in kg/metric ton of aluminum produced shall be determined using the following equation:

$$E_{pp}=\frac{(C_sQ_s)_1\,10^{-6}+(C_sQ_s)_2\,10^{-6}}{M}$$

where:

E_{pp}=potroom group emissions of total fluorides in kg/metric ton of aluminum produced.

C_s=concentration of total fluorides in mg/dscm as determined by Method 13A or 13B, or by Method 14, as applicable.

Q_s=volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2 and/or Method 14, as applicable

10^{-6}=conversion factor from mg to kg

M=rate of aluminum production in metric ton/hr as determined by § 60.195(d)

$(C_sQ_s)_2$=product of C_s and Q_s for measurements of primary control system effluent gas streams.

$(C_sQ_s)_1$=product of C_s and Q_s for measurements of secondary control system or roof monitor effluent gas streams

(g) For each run, as applicable, anode bake plant emissions expressed in kg/metric ton of aluminum equivalent shall be determined using the following equation:

$$E_{bp}=\frac{C_sQ_s\,10^{-6}}{M_e}$$

Where:

E_{bp}=anode bake plant emissions of total fluorides in kg/metric ton of aluminum equivalent.

C_s=concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.

Q_s=volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.

10^{-6}=conversion factor from mg to kg.

M_e=aluminum equivalent for anodes produced by anode bake plants in metric ton/hr as determined by § 60.195(e).

3. Part 60 is amended by adding Reference Method 14 to Appendix A as follows:

METHOD 14—DETERMINATION OF FLUORIDE EMISSIONS FROM POTROOM ROOF MONITORS OF PRIMARY ALUMINUM PLANTS

1. *Principle and applicability.*

1.1 *Principle.* Gaseous and particulate fluoride roof monitor emissions are drawn into a permanent sampling manifold through several large nozzles The sample is transported from the sampling manifold to ground level through a duct. The gas in the duct is sampled using Method 13A or 13B—DETERMINATION OF TOTAL FLUORIDE EMISSIONS FROM STATIONARY SOURCES. Effluent velocity and volumetric flow rate are determined with anemometers permanently located in the roof monitor.

1.2 *Applicability* This method is applicable for the determination of fluoride emissions from stationary sources only when specified by the test procedures for determining compliance with new source performance standards.

2. *Apparatus.*

2.1.1 *Anemometers.* Vane or propeller anemometers with a velocity measuring threshold as low as 15 meters/minute and a range up to at least 600 meters/minute. Each anemometer shall generate an electrical signal which can be calibrated to the velocity measured by the anemometer. Anemometers shall be able to withstand dusty and corrosive atmospheres.

One anemometer shall be installed for every 85 meters of roof monitor length. If the roof monitor length divided by 85 meters is not a whole number, round the fraction to the nearest whole number to determine the number of anemometers needed. Use one anemometer for any roof monitor less than 85 meters long. Permanently mount the anemometers at the center of each equal length along the roof monitor. One anemometer shall be installed in the same section of the roof monitor that contains the sampling manifold (see section 2.2.1) Make a velocity traverse of the width of the roof monitor where an anemometer is to be placed This traverse may be made with any suitable low velocity measuring device, and shall be made during normal process operating conditions Install the anemometer at a point of average velocity along this traverse

2.1.2 *Recorders.* Recorders equipped with signal transducers for converting the electrical signal from each anemometer to a continuous recording of air flow velocity, or to an integrated measure of volumetric flow. For the purpose of recording velocity, "continuous" shall mean one readout per 15-minute or shorter time interval. A constant amount of time shall elapse between readings Volumetric flow rate may be determined by an electrical count of anemometer revolutions The recorders or counters shall permit identification of the velocities or flow rate measured by each individual anemometer.

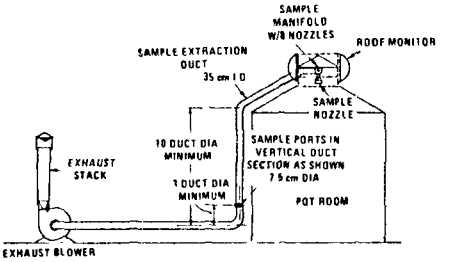


Figure 14 1 Roof Monitor Sampling System

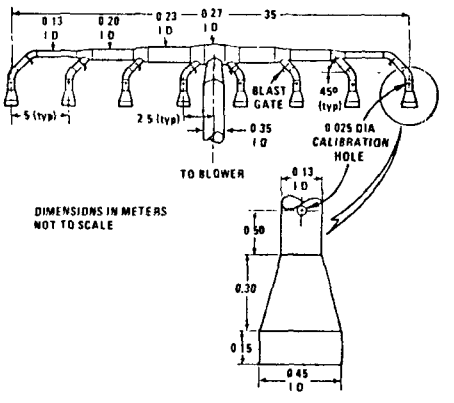


Figure 14 2 Sampling Manifold and Nozzles

2.2 Roof monitor air sampling system

2.2.1 *Sampling ductwork* The manifold system and connecting duct shall be permanently installed to draw an air sample from the roof monitor to ground level. A typical installation of duct for drawing a sample from a roof monitor to ground level is shown in Figure 14-1. A plan of a manifold system that is located in a roof monitor is shown in Figure 14-2. These drawings represent a typical installation for a generalized roof monitor. The dimensions on these figures may be altered slightly to make the manifold system fit into a particular roof monitor, but the general configuration shall be followed. There shall be eight nozzles, each having a diameter of 0.40 to 0.50 meters. The length of the manifold system from the first nozzle to the eighth shall be 35 meters or eight percent of the length of the roof monitor, whichever is greater. The duct leading from the roof monitor manifold shall be round with a diameter of 0.30 to 0.40 meters. As shown in Figure 14-2, each of the sample legs of the manifold shall have a device, such as a blast gate or valve, to enable adjustment of flow into each sample nozzle.

Locate the manifold along the length of the roof monitor so that it lies near the midsection of the roof monitor If the design of a particular roof monitor makes this impossible, the manifold may be located elsewhere along the roof monitor but avoid locating the manifold near the ends of the roof monitor or in a section where the aluminum reduction pot arrangement is not typical of the rest of the potroom Center the sample nozzles in the throat of the roof monitor (See Figure 14-1) Construct all sample-exposed surfaces within the nozzles, manifold and sample duct of 316 stainless steel Aluminum may be used if a new ductwork system is conditioned with fluoride-laden roof monitor air for a period of six weeks prior to initial testing Other materials of construction may be used if it is demonstrated through comparative testing that there is no loss of fluorides in the system All connections in the ductwork shall be leak free

Locate two sample ports in a vertical section of the duct between the roof monitor and exhaust fan The sample ports shall be at least 10 duct diameters downstream and two diameters upstream from any flow disturbance such as a bend or contraction The two sample ports shall be situated 90° apart One of the sample ports shall be situated so that the duct can be traversed in the plane of the nearest upstream duct bend

2 2 2 *Exhaust fan* An industrial fan or blower to be attached to the sample duct at ground level (See Figure 14-1) This exhaust fan shall have a maximum capacity such that a large enough volume of air can be pulled through the ductwork to maintain an isokinetic sampling rate in all the sample nozzles for all flow rates normally encountered in the roof monitor

The exhaust fan volumetric flow rate shall be adjustable so that the roof monitor air can be drawn isokinetically into the sample nozzles This control of flow may be achieved by a damper on the inlet to the exhauster or by any other workable method

2 3 Temperature measurement apparatus

2 3 1 *Thermocouple* Installed in the roof monitor near the sample duct

2 3 2 *Signal transducer* Transducer to change the thermocouple voltage output to a temperature readout

2 3 3 *Thermocouple wire* To reach from roof monitor to signal transducer and recorder

2 3 4 *Sampling train.* Use the train described in Methods 13A and 13B—Determination of total fluoride emissions from stationary sources.

3. Reagents

3 1 *Sampling and analysis* Use reagents described in Method 13A or 13B—Determination of total fluoride emissions from stationary sources.

4 Calibration

4 1 *Propeller anemometer* Calibrate the anemometers so that their electrical signal output corresponds to the velocity or volumetric flow they are measuring Calibrate according to manufacturer's instructions

4 2 *Manifold intake nozzles* Adjust the exhaust fan to draw a volumetric flow rate (refer to Equation 14-1) such that the entrance velocity into each manifold nozzle approximates the average effluent velocity in the roof monitor Measure the velocity of the air entering each nozzle by inserting an S type pitot tube into a 2 5 cm or less diameter hole (see Figure 14 2) located in the manifold between each blast gate (or valve) and nozzle The pitot tube tip shall be extended into the center of the manifold Take care to insure that there is no leakage around the pitot probe which could affect the indicated velocity in the manifold leg If the velocity of air being drawn into each nozzle is not the same, open or close each blast gate (or valve) until the velocity in each nozzle is the same Fasten each blast gate (or valve) so that it will remain in this position and close the pitot port holes This calibration shall be performed when the manifold system is installed (Note: It is recommended that this calibration be repeated at least once a year)

5 Procedure

5 1 *Roof monitor velocity determination*

5 1.1 *Velocity value for setting isokinetic flow.* During the 24 hours preceding a test run, determine the velocity indicated by the propeller anemometer in the section of roof monitor containing the sampling manifold. Velocity readings shall be taken every 15 minutes or at shorter equal time intervals Calculate the average velocity for the 24-hour period.

5 1 2 *Velocity determination during a test run* During the actual test run, record the velocity or volume readings of each propeller anemometer in the roof monitor Velocity readings shall be taken for each anemometer every 15 minutes or at shorter equal time intervals (or continuously)

5.2 *Temperature recording.* Record the temperature of the roof monitor every two hours during the test run.

5 3 *Sampling*

5 3 1 *Preliminary air flow in duct* During the 24 hours preceding the test, turn on the exhaust fan and draw roof monitor air through the manifold duct to condition the ductwork Adjust the fan to draw a volumetric flow through the duct such that the velocity of gas entering the manifold nozzles approximates the average velocity of the air leaving the roof monitor

5 3 2 *Isokinetic sample rate adjustment* Adjust the fan so that the volumetric flow rate in the duct is such that air enters into the manifold sample nozzles at a velocity equal to the 24-hour average velocity determined under 5 1 1 Equation 14-1 gives the correct stream velocity which is needed in the duct at the sample ports in order for sample gas to be drawn isokinetically into the manifold nozzles Perform a pitot traverse of the duct at the sample ports to determine if the correct average velocity in the duct has been achieved Perform the pitot determination according to Method 2 Make this determination before the start of a test run The fan setting need not be changed during the run.

$$V_d = \frac{8\,(D_n)^2}{(D_d)^2}\,(V_m)\,\frac{1\text{ minute}}{60\text{ sec}}$$

where:

V_d=desired velocity in duct at sample ports, meter/sec

D_n=diameter of a roof monitor manifold nozzle, meters.

D_d=diameter of duct at sample port, meters

V_m=average velocity of the air stream in the roof monitor, meters/minute, as determined under section 5 1 1.

5 2 3 *Sample train operation.* Sample the duct using the standard fluoride train and methods described in Methods 13A and 13B Determination of total fluoride emissions from stationary sources Select sample traverse points according to Method 1. If a selected sampling point is less than one inch from the stack wall, adjust the location of that point to one inch away from the wall.

5 3 4 *Each test run shall last eight hours or more* If a question exists concerning the representativeness of an eight-hour test, a longer test period up to 24 hours may be selected Conduct each run during a period when all normal operations are performed underneath the sampling manifold, i.e. tapping, anode changes, maintenance, and other normal duties. All pots in the potroom shall be operated in a normal manner during the test period

5 3 5 *Sample recovery.* Same as Method 13A or 13B—Determination of total fluoride emissions from stationary sources

5 4 *Analysis* Same as Method 13A or 13B—Determination of total fluoride emissions from stationary sources.

6 Calculations

6 1 *Isokinetic sampling test.* Calculate the mean velocity measured during each sampling run by the anemometer in the section of the roof monitor containing the sampling manifold If the mean velocity recorded during a particular test run does not fall within ±20 percent of the mean velocity established according to 5 3 2, repeat the run.

6 2 *Average velocity of roof monitor gases.* Calculate the average roof monitor velocity using all the velocity or volumetric flow readings from section 5 1 2.

6 3 *Roof monitor temperature* Calculate the mean value of the temperatures recorded in section 5 2

6 4 *Concentration of fluorides in roof monitor air in mg F/m* This is given by Equation 13A-5 in Method 13A—Determination of total fluoride emissions from stationary sources

6 5 Average volumetric flow from roof is given by Equation 14-2

$$Q_m = \frac{V_{mf}\,(A)\,(M_d)\,P_m\,(294°\text{K})}{(T_m + 273°)\,(760\text{ mm Hg})}$$

where:

Q_m=average volumetric flow from roof monitor at standard conditions on a dry basis, m³/min.

A=roof monitor open area, m².

V_{mf}=average velocity of air in the roof monitor, meters/minute, from section 6 2

P_m=atmospheric pressure, mm Hg

T_m=roof monitor temperature, °C, from section 6 3

M_d=mole fraction of dry gas, which is given by $M_d = \frac{100 - 100\,(B_{wo})}{100}$

B_{wo}=is the proportion by volume of water vapor in the gas stream, from Equation 13A-3, Method 13A—Determination of total fluoride emissions from stationary sources

[Sections 111 and 114 of the Clean Air Act, as amended by section 4(a) of Pub. L. 91-604, 84 Stat. 1678 (42 U S.C. 1857c-6, c-9)].

[FR Doc.76-2133 Filed 1-23-76;8:45 am]

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 483-7]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to Washington Local Agencies

Pursuant to section 111(c) of the Clean Air Act, as amended, the Regional Administrator of Region X, Environmental Protection Agency (EPA), delegated to the State of Washington Department of Ecology on February 28, 1975, the authority to implement and enforce the program for standards of performance for new stationary sources (NSPS). The delegation was announced in the FEDERAL REGISTER on April 1, 1975 (40 FR 14632). On April 25, 1975 (40 FR 18169) the Assistant Administrator for Air and Waste Management promulgated a change to 40 CFR 60.4, Address to reflect the delegation to the State of Washington.

On September 30 and October 8 and 9, 1975, the State Department of Ecology requested EPA's concurrence in the State's sub-delegation of the NSPS program to four local air pollution control agencies. After reviewing the State's request, the Regional Administrator determined that the subdelegations meet all the requirements outlined in EPA's delegation of February 28, 1975. Therefore, the Regional Administrator on December 5, 1975, concurred in the subdelegations to the four local agencies listed below with the stipulation that all the conditions placed on the original delegation to the State shall also apply to the sub-delegations to the local agencies. EPA is today amending 40 CFR 60.4 to reflect the State's sub-delegations.

The amended § 60.4 provides that all reports, requests, applications, submittals and communications required pursuant to Part 60 which were previously to be sent to the Director of the State of Washington Department of Ecology (DOE) will now be sent to the Puget Sound Air Pollution Control Agency (PSAPCA), the Northwest Air Pollution Authority (NWAPA), the Spokane County Air Pollution Authority (SCAPA) or the Southwest Air Pollution Control Authority (SAPCA) as appropriate. The amended section is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegations which are reflected by the administrative amendment were effective on September 30 to the NWAPA, October 7 to the PSAPCA and October 8 to the SCAPA and the SAPCA, and it serves no useful purpose to delay the technical change of the addition of the local agency addresses to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended. 42 U.S.C. 1857c-6.

Dated: January 24, 1976.

STANLEY W. LEGRO,
Assistant Administrator for Enforcement.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4, paragraph (b) is amended by revising subparagraph (WW) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(WW) (i) Washington; State of Washington, Department of Ecology, Olympia, Washington 98504.

(ii) Northwest Air Pollution Authority, 207 Pioneer Building, Second and Pine Streets, Mount Vernon, Washington 98273.

(iii) Puget Sound Air Pollution Control Agency, 410 West Harrison Street, Seattle, Washington 98119.

(iv) Spokane County Air Pollution Control Authority, North 811 Jefferson, Spokane, Washington 99201.

(v) Southwest Air Pollution Control Authority, Suite 7601 H, NE Hazel Dell Avenue, Vancouver, Washington 98665.

* * * * * *

[FR Doc.76-2673 Filed 1-28-76;8:45 am]

Title 40—Protection of Environment

[FRL 492-3]

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State of Oregon

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of Oregon on November 10, 1975, EPA is today amending 40 CFR 60.4, *Address*, to reflect this delegation. A Notice announcing this delegation is published today at 41 FR 7750 in the FEDERAL REGISTER. The amended § 60.4 which adds the address of the State of Oregon Department of Environmental Quality to which all reports, requests, applications, submittals, and communications pursuant to this part must be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on November 10, 1975 and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended. 42 U.S.C. 1857c-6.

Dated: February 11, 1976.

STANLEY W. LEGRO,
Assistant Administrator for Enforcement.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (MM) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)-(LL) * * *

(MM)—State of Oregon, Department of Environmental Quality, 1234 SW Morrison Street, Portland, Oregon 97205.

* * * * *

[FR Doc.76-4964 Filed 2-19-76;8:45 am]

30

Title 40—Protection of Environment

[FRL 494-3]

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Primary Copper, Zinc, and Lead Smelters; Correction

In FR Doc. 76-733 appearing at page 2331 in the FEDERAL REGISTER of January 15, 1976, the ninth line of paragraph (a) in § 60.165 is corrected to read as follows: "total smelter charge and the weight."

Dated: February 20, 1976.

ROGER STRELON,
Assistant Administrator for Air and Waste Management.

[FR Doc.76-5398 Filed 2-25-76;8:45 am]

[FRL 495-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to Commonwealth of Virginia

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the Commonwealth of Virginia on December 30, 1975, EPA is today amending 40 CFR 60.4, *Address*, to reflect this delegation. A Notice announcing this delegation is published today at 41 FR 8416 in the FEDERAL REGISTER. The amended § 60.4, which adds the address of the Virginia State Air Pollution Control Board to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on December 30, 1975, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of section 111 of the Clean Air Act, as amended. 42 U.S.C. 1857c-6.

42 U.S.C. 1857c-6.

Dated: February 21, 1976

STANLEY W. LEGRO,
Assistant Administrator for Enforcement.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4, paragraph (b) is amended by revising subparagraph (VV) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)-(UU) * * *

(VV) Commonwealth of Virginia, Virginia State Air Pollution Control Board, Room 1106, Ninth Street Office Building, Richmond, Virginia 23219.

[FR Doc.76-5504 Filed 2-25-76;8:45 am]

31

SUBCHAPTER C—AIR PROGRAMS

[FRL 507-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCE

Delegation of Authority to State of Connecticut

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of Connecticut on December 9, 1975, EPA is today amending 40 CFR 60.4, *Address*, to reflect this delegation. A Notice announcing this delegation is published today at (41 FR 11874) in the FEDERAL REGISTER. The amended § 60.4, which adds the address of the Connecticut Department of Environmental Protection to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on December 9, 1975, and it serves no purpose to delay the technical change of this addition to the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of section 111 of the Clean Air Act, as amended.

(42 U.S.C. 1857c-6)

Dated: March 15, 1976.

STANLEY W. LEGRO,
Assistant Administrator for Enforcement.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (H) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(H) State of Connecticut, Department of Environmental Protection, State Office Building, Hartford, Connecticut 06115.

* * * * *

[FR Doc.76-7967 Filed 3-19-76;8:45 am]

32

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 529-3]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCE

Delegation of Authority to State of South Dakota

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of South Dakota on March 25, 1976, EPA is today amending 40 CFR 60.4, Address, to reflect this delegation. A Notice announcing this delegation is published today at 41 FR 17600. The amended § 60.4, which adds the address of Department of Environmental Protection to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on March 25, 1976, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended.

42 U.S.C. 1857c-6.

Date: April 20, 1976.

STANLEY W. LEGRO,
Assistant Administrator for Enforcement.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph QQ to read as follows:

§ 60.4 Address.

* *

(b) * * *

(A)-(Z) * * *

(AA)-(PP) * * *

(QQ) State of South Dakota, Department of Environmental Protection, Joe Foss Building, Pierre, South Dakota 57501.

33

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 509-3]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Ferroalloy Production Facilities

On October 21, 1974 (39 FR 37470), under section 111 of the Clean Air Act, as amended, the Environmental Protection Agency (EPA) proposed standards of performance for new and modified ferroalloy production facilities. Interested persons participated in the rulemaking by submitting comments to EPA. The comments have been carefully considered, and where determined by the Administrator to be appropriate, changes have been made to the regulations as promulgated.

The standards limit emissions of particulate matter and carbon monoxide from ferroalloy electric submerged arc furnaces. The purpose of the standards is to require effective capture and control of emissions from the furnace and tapping station by application of best systems of emission reduction. For ferroalloy furnaces the best system of emission reduction for particulate matter is a well-designed hood in combination with a fabric filter collector or venturi scrubber. For some alloys the best system is an electrostatic precipitator preceded by wet gas conditioning or a venturi scrubber. The standard for carbon monoxide requires only that the gas stream be flared or combusted in some other manner.

The environmental impact of these standards is beneficial since the increase in emissions due to growth of the industry will be minimized. Also, the standards will remove the incentive for plants to locate in areas with less stringent regulations.

Upon evaluation of the costs associated with the standards and their economic impact, EPA concluded that the costs are reasonable and should not bar entry into the market or expansion of facilities. In addition, the standards will require at most a minimal increase in power consumption over that required to comply with the restrictions of most State regulations.

SUMMARY OF REGULATION

The promulgated standards limit particulate matter and carbon monoxide emissions from the electric submerged arc furnace and limit particulate matter emissions from dust-handling equipment. Emissions of particulate matter from the control device are limited to less than 0.45 kg/MW-hr (0.99 lb/MW-hr) for furnaces producing high-silicon alloys (in general) and to less than 0.23 kg/MW-hr (0.51 lb/MW-hr) for furnaces producing chrome and manganese alloys. For both product groups, emissions from the control device must be less than 15 percent opacity. The regulation requires that the collection hoods capture all emissions generated within the furnace and capture all tapping emissions for at least 60 percent of the tapping time. The concentration of carbon monoxide in any gas stream discharged to the atmosphere must be less than 20 volume percent. Emissions from dust-handling equipment may not equal or exceed 10 percent opacity. Any owner or operator of a facility subject to this regulation must continuously monitor volumetric flow rates through the collection system and must continuously monitor the opacity of emissions from the control device.

SUMMARY OF COMMENTS

Eighteen comment letters were received on the proposed standards of performance. Copies of the comment letters and a report which contains a summary of the issues and EPA's responses are available for public inspection and copying at the U.S. Environmental Protection Agency, Public Information Reference Unit (EPA Library), Room 2922, 401 M Street, S.W., Washington, D.C. Copies of the report also may be obtained upon written request from the EPA Public Information Center (PM-215), 401 M Street, S.W., Washington, D.C. 20460 (specify—Supplemental Information on Standards of Performance for Ferroalloy Production Facilities). In addition to the summary of the issues and EPA's responses, the report contains a reevaluation of the opacity standard in light of revisions to Reference Method 9 which were published in the FEDERAL REGISTER November 12, 1974 (39 FR 39872).

The bases for the proposed standards are presented in "Background Information for Standards of Performance: Electric Submerged Arc Furnaces for Production of Ferroalloys" (EPA 450/2-74-018a, b). Copies of this document are available on request from the Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention: Mr. Don R. Goodwin.

SIGNIFICANT COMMENTS AND CHANGES TO THE PROPOSED REGULATION

Most of the comment letters contained multiple comments. The more significant comments and the differences between the proposed and the final regulations are discussed below. In addition to the discussed changes, several paragraphs were reworded and some sections were reorganized.

(1) *Mass standard.* Several commenters questioned the representativeness of the data used to demonstrate the achievability of the 0.23 kg/MW-hr (0.51 lb/MW-hr) standard proposed for facilities producing chrome and manganese alloys. Specifically, the commenters were concerned that sampling only a limited number of compartments or control devices serving a furnace, nonisokinetic sampling of some facilities, and the procedures used to determine the total gas volume flow from open fabric filter collectors would bias the data low. For these reasons, the commenters argued that the standard should be 0.45 kg/MW-hr (0.99 lb/MW-hr) for all alloys. As additional support for their position, they claimed that control equipment vendors will not guarantee that their equipment will achieve 0.23 kg/MW-hr (0.51 lb/MW-hr).[35]

Because of these comments, EPA thoroughly reevaluated the bases for the two mass standards of performance and concluded that the standards are achievable by best systems of emission reduction. For open ferroalloy electric submerged arc furnaces, the best system of emission reduction is a well-designed canopy hood that minimizes the volume of induced air and a well-designed and properly operated fabric filter collector or high-energy venturi scrubber. In a few cases, an electrostatic precipitator preceded by a venturi scrubber or wet gas conditioning is a best system. In EPA's opinion, revising the standard upward to 0.45 kg/MW-hr (0.99 lb/MW-hr) would allow installation of systems other than the best. Therefore, the promulgated standard of performance for furnaces producing chrome and manganese alloys is 0.23 kg/MW-hr (0.51 lb/MW-hr). The standard for furnaces producing the specified high-silicon alloys is 0.45 kg/MW-hr (0.99 lb/MW-hr). The rationale for establishing the standards at these levels is summarized below.

The reevaluation of the data bases for the standards showed that the emission test procedures used did not significantly bias the results. Therefore, contrary to the commenter's concerns, the procedures did not result in emission limitations lower than those achievable by best systems of emission reduction. The deviations and assumptions made in the test procedures were based on consideration of the particle size of the emissions, an evaluation of the performance of the control systems, and factors affecting the induction of air into open fabric filter collectors.

EPA tests, and allows testing of, a representative number of stacks or compartments in a control device because subsections of a well-designed and properly operating control device will perform equivalently. Evaluation of the control system and the condition of the control device by EPA engineers at the time of the emission test showed that sections not tested were of equivalent design and in operating condition equivalent to or better than the tested sections. Thus, the performance of the non-tested portions of the control device are considered to be equivalent to or better than the performance of the sections emission tested. In addition, the particle size of emissions from well-controlled ferroalloy furnaces was investigated by EPA and was found to consist of particles of less than two micrometers aerodynamic diameter for all alloys. The mass and, hence, inertia of these particles are negligible; therefore, they follow the motion of the gas stream. For emissions of this size distribution, concentrations determined by nonisokinetic sampling would not be significantly different than those measured by isokinetic sampling.

EPA determined the total gas volume flow rate from the open fabric filter collectors by measuring the inlet volume flow rate and the volume of air induced into the collector. The inlet gas volumes

to the collectors were measured during each run of each test; but the volume of air induced into the collector was determined once during the emission test. The total gas volume flow from the collector was calculated as the sum of the inlet gas volume and the induced air volume. Although the procedures used were not ideal, the reported gas volumes are considered to be reasonably representative of the total gas volumes from the facility. This conclusion is based on the fact that the quantity of air induced around the bags in an open collector is primarily dependent on the open area and the temperature of the inlet gas stream and the ambient air. Therefore, equivalent air volumes are drawn into the collector under similar meteorological and inlet gas conditions. During the periods of emission testing at the facilities, meteorological conditions were uniform and the volume of induced air was expected to be constant. Consequently, measurement of the induced air volume once during the emission test was expected to be sufficient for calculating the total gas volume flow from the collector.

Since conducting the test in question, EPA has gained additional experience and has concluded that in general it is preferable to measure the total gas volume flow during each run of a performance test. This conclusion, however, does not invalidate the use of the test data obtained by the less optimum procedure of a single determination of induced air volume. EPA evaluated possible variations in the amount of air induced into the collector by performing enthalpy balances using reported temperature data. The induced air volumes were calculated assuming adiabatic mixing (no heat transfer by inlet gases to collector) and, hence, are conservatively high estimates. The calculated induced air volumes did differ from the single measured values; however, the effect on the mass emission rate for the collectors was not significant. EPA, therefore, concluded that the use of single measurements of the induced air volume did not affect the level of the standards.

Another issue of concern to commenters is the reluctance of control equipment vendors to guarantee reduction of emissions to less than 0.23 kg/MW-hr (0.51 lb/MW-hr). It is EPA's opinion that this reluctance does not demonstrate the unachievability of the standard. The vendors' reluctance to guarantee this level is not surprising considering the variables which are beyond their control. Specifically, they rarely have any control over the design of the fume collection systems for the furnace and tapping station. Fabric filter collectors tend to control the concentration of particulate matter in the effluent. The mass rate of emissions from the collector is determined by the total volumetric flow rate from the control device, which is not determined by vendors. Further, because of limited experience with emission testing to evaluate the performance of open fabric filter collectors, vendors cannot effectively evaluate the performance of these systems over the guarantee period. For vendors, establishment of the performance guarantee level is also complicated by the fact that the performance of the collector is contingent upon its being properly operated and maintained.

Standards of performance are necessarily based on data from a limited number of best-controlled facilities and on engineering judgments regarding performance of the control systems. For this reason, there is a possibility of arriving at different conclusions regarding the performance capabilities of these systems. Consequently, the question of vendors' reluctance to guarantee their equipment to achieve 0.23 kg/MW-hr (0.51 lb/MW-hr) was considered along with the results of additional recent emission tests on fabric filter collectors. Recognizing that the data base for the standards was limited and that a number of well-controlled facilities had started operation since completion of the original study, EPA obtained additional data to better evaluate the performance of emission control systems of interest. Under the authority of section 114 of the Clean Air Act, EPA requested copies of all emission data for well-controlled furnaces operated by 10 ferroalloy producers. Data were received for five well-controlled facilities. In general, these facilities had close fitting water cooled canopy hoods, and tapping fumes were collected and sent to the control device along with the furnace emissions.

The emission data submitted by the industry show that properly operating compartments of open fabric filter collectors have effluent concentrations of less than 0.009 g/dscm (0.004 gr/dscf). For these recently constructed facilities, the reported mass emission rates were less than 0.12 kg/MW-hr (0.24 lb/MW-hr) for 15 MW capacity silicon metal furnaces. Evaluation of possible errors in the data and uncertainties in the test procedures showed that emissions may have been as high as 0.20 kg/MW-hr (0.45 lb/MW-hr) in some cases. These emission rates were achieved by design of the collection hood to minimize the quantity of induced air. The data submitted by the industry showed that gas volumes from well-hooded large silicon metal furnaces can be reduced to 50 percent of the volumes from typically hooded large silicon furnaces. Based on the data obtained from the industry, a large well-hooded and well-controlled silicon metal furnace is expected to have an emission rate of less than 0.45 kg/MW-hr (0.99 lb/MW-hr).

In EPA's study of the ferroalloy industry, it was determined that emissions from production of high-silicon alloys would be more difficult to control than chrome and manganese emissions due to the finer size distribution of the particles and significantly larger gas volumes from the furnace. Comparison of the gas volumes reported by the industry from silicon metal production with gas volumes from typically hooded furnaces producing chrome and manganese alloys shows that the original conclusion is still valid. Due to the lower gas volumes associated with their production, a lower mass emission rate is still expected for chrome and manganese alloys. In addition, EPA emission tests in the original study on a number of tightly hooded open furnaces demonstrated emissions can be controlled to less than 0.23 kg/MW-hr (0.51 lb/MW-hr). Emissions were reduced to these levels by control of induced air volumes and by use of a well-designed and properly operated fabric filter collector or venturi scrubber.

Just before promulgation of the standards, members of the Ferroalloy Association informed EPA that future supplies of chrome and manganese ores will be finer and more friable than those in use during development of the standard. The industry representatives claimed that use of finer ores will affect furnace operations and prevent new furnaces from complying with the 0.23 kg/MW-hr (0.51 lb/MW-hr) standard. Although the representatives submitted statements concerning the effect of finer ores on furnace operating conditions, no data were provided to show the effect of ore size on emissions. EPA evaluated the material submitted and concluded that furnace operating problems associated with use of fine ores can be controlled by operation and maintenance procedures. With proper operation of the furnace, use of finer ores should not affect the achievability of the standard, and relaxation of the 0.23 kg/MW-hr (0.51 lb/MW-hr) standard is not justified. This evaluation is discussed in detail in Chapter II of the supplemental information document. If and when factual information is presented to EPA which clearly demonstrates that use of finer chrome and manganese ores does prevent a properly operated new furnace, which is equipped with the best demonstrated system of emission reduction (considering costs), from meeting the 0.23 kg/MW-hr (0.51 lb/MW-hr) standard, EPA will propose a revision to the standard. The best system of emission reduction (considering costs) is considered to be a well-designed collection hood in combination with a well-designed fabric filter collector or high-energy venturi scrubber

The emission data obtained by EPA and the data provided by the industry show that the standards of performance for both product groups are achievable and the required control system clearly is adequately demonstrated. The question of the achievability of and the validity of the data basis for both the 0.23 kg/MW-hr (0.51 lb/MW-hr) and 0.45 kg/MW-hr (0.99 lb/MW-hr) standards is discussed in more detail in Chapter II of the supplemental information document.

(2) *Control device opacity standard.* On November 12, 1974 (39 FR 39872), after proposal of the standards for ferroalloy facilities, Method 9 was revised to require that compliance with opacity standards be determined by averaging sets of 24 consecutive observations taken at 15-second intervals (six-minute averages). The proposed opacity standard which limited emissions from the control

device to less than 20 percent has been revised in the regulation promulgated herein to require that emissions be less than 15 percent opacity in order to retain the intended level of control.

(3) *Control system capture requirements.* Ten commenters criticized fume capture requirements for the furnace and tapping station control systems on two basic points. The arguments were: (1) EPA lacks the statutory authority to regulate emissions within the building, and (2) the standards are not technically feasible at all times.

EPA has the statutory authority under section 111 of the Act to regulate any new stationary source which "emits or may emit any air pollutant." EPA does not agree with the opinion of the commenters that section 111 of the Act expressly or implicitly limits the Agency to regulation only of pollutants which are emitted directly into the atmosphere. Particulate matter emissions escaping capture by the furnace control system ultimately will be discharged to the atmosphere outside of the shop; therefore, they may be regulated under section 111 of the Act. Standards which regulate pollutants at the point of emission inside the building allow assessment of the control system without interference from nonregulated sources located in the same building. In addition, by requiring evaluation of emissions before their dilution, the standards will result in better control of the furnace emissions and will regulate affected ferroalloy facilities more uniformly than would standards limiting emissions from the shop.

EPA believes the standards on the furnace and tapping station collection hoods are achievable because the standards are based on observations of normal operations at well-controlled facilities. The commenters who argued that the standards are not technically feasible at all times cited examples of abnormal operations which would preclude achieving the standards. For example, several commenters cited the fact that violent reactions due to imbalances in the alloy chemistry occasionally can generate more emissions than the hood was designed to capture. If the capture system is well-designed, well-maintained, and properly operated, only failures of the process to operate in the normal or usual manner would cause the capacity of the system to be exceeded. Such operating periods are malfunctions, and, therefore, compliance with the standards of performance would not be determined during these periods. Performance tests under 40 CFR 60.8(c) are conducted only during representative conditions, and periods of start-up, shutdown, and malfunctions are not considered representative conditions.

Five commenters discussed other operating conditions which they believed would preclude a source from complying with the tapping station standard. These conditions included blowing taps, period of poling the taphole, and periods of removal of metal and slag from the spout. The commenters argued that blowing taps should be exempted from the standard and the tapping station standard should be replaced with an opacity standard or emissions from the shop. The comments were reviewed and EPA concluded that exemption of blowing taps is justified. The regulation promulgated herein exempts blowing taps from the tapping station standard and includes a definition of blowing tap. EPA believes that conditions which result in plugging of the taphole and metal in the spout are malfunctions because they are unavoidable failures of the process to operate in the normal or usual manner. Discussions with experts in the ferroalloy industry, revealed that these conditions are not predictable conditions for which a preventative maintenance or operation program could be established. As malfunctions, these periods are not subject to the standards, and a performance test would not be conducted during such periods. Therefore, the suggested revision to the standard to exempt these periods is not necessary because of the existing provisions of 40 CFR 60.8(c) and 60.11. In EPA's judgment, both the furnace and tapping station standards are achievable for all normal process operations at facilities with well-designed, well-maintained and properly operated emission collection systems.

The promulgated regulation retains the proposed fume capture requirements, but the regulation has been revised to be more enforceable than the proposed capture requirements, which could have been enforced only on an infrequent basis. The regulation has been reorganized to clarify that unlike the opacity standards, the collection system capture requirements (visible emission limitations) are subject to demonstration of compliance during the performance test. To provide a means for routine enforcement of the capture requirements, continuous monitoring of the volumetric flow rate(s) through the collection system is required for each affected furnace. An owner or operator may comply with this requirement either by installing a flow rate monitoring device in an appropriate location in the exhaust duct or by calculating the flow rate through the system from fan operating data. During the performance test, the baseline operating flow rate(s) will be established for the affected electric submerged arc furnace. The regulation establishes emission capture standards which are applicable only during the performance test of the affected facility. At all other times, the operating volumetric flow rate(s) shall be maintained at or greater than the established baseline values for the furnace load. Use of lower volumetric flow rates than the established values constitutes unacceptable operation and maintenance of the affected facility. These provisions of the promulgated regulation will ensure continuous monitoring of the operations of the emission capture system and will simplify enforcement of the emission capture requirements.

The requirements for monitoring volumetric flow rates will add negligible additional costs to the total costs of complying with the standards of performance. Flow rate monitoring devices of sufficient accuracy to meet the requirements of § 60.265(c) can be installed for $600–$4000 depending on the flow profile of the area being monitored and the complexity of the monitoring device. A suitable strip chart recorder can be installed for less than $600. The alternative provisions allowing calculation of the volumetric flow rate(s) through the control system from continuous monitoring of fan operations will result in no additional costs because the industry presently monitors fan operations.

(4) *Monitoring of operations.* The promulgated regulation requires reporting to the Administrator any product changes that will result in a change in the applicable standard of performance for the affected electric submerged arc furnace. This requirement is necessary because electric submerged arc furnaces may be converted to production of alloys other than the original design alloys by physical alterations to the furnace, changes to the electrode spacing, changes in the transformer capacity, and changes in the materials charged to the furnace. Thus, the emission rate from the electric submerged arc furnace and the standard of performance (which is dependent on the alloy produced) may change during the lifetime of the facility. Conversion of the furnace to production of alloys with significantly different emission rates, such as changes between the product groups for the two standards, may result in the facility exceeding the applicable standard. Consequently, the reporting requirement was added to ensure continued compliance with the applicable standards of performance. These reports of product changes will afford the Administrator an opportunity to determine whether a performance test should be conducted and will simplify enforcement of the regulation. As with the requirements applicable under the proposed regulation, the performance test still must be conducted while the electric submerged arc furnace is producing the design alloy whose emissions are the most difficult to control of the product family. Subsequent product changes within the product family will not cause the facility to exceed the standard.

(5) *Test methods and procedures.* Section 60.266(d) of the promulgated regulation requires the owner or operator to design and construct the control device to allow measurement of emissions and flow rates using applicable test methods and procedures. This provision permits the use of open pressurized fabric filter collectors (and other control devices) whose emissions cannot be measured by reference methods currently in Appendix A to this part, if compliance with the promulgated standard can be demonstrated by an alternative procedure. EPA has not specified a single test procedure for emission testing of open pressurized fabric filter collectors because of the large variations in the design of these collectors. Test procedures can be developed on a case-by-case basis, however. Provisions in 40 CFR 60.8(b) allow the owner or operator upon approval by the Administrator to use an "alternative" or

"equivalent" test procedure to show compliance with the standards. EPA would like to emphasize that development of the "alternative" or "equivalent" test procedure is the responsibility of any owner or operator who elects to use a control device not amenable to testing by Method 5 of Appendix A to this part. The procedures of an "alternative" test method for demonstration of compliance are dependent on specific design features and condition of the collector and the capabilities of the sampling equipment. Consequently, procedures acceptable for demonstration of compliance will vary with specific situations. General guidance on possible approaches to sampling of emissions from pressurized fabric filter collectors is provided in Chapter IV of the supplemental information document.

Due to the costs of testing, the owner or operator should obtain EPA approval for a specific test procedure or other means for determining compliance before construction of a new source. Under the provisions of § 60.6, the owner or operator of a new facility may request review of the acceptability of proposed plans for construction and testing of control systems which are not amenable to sampling by Reference Method 5. If an acceptable "alternative" test procedure is not developed by the owner or operator, then total enclosure of the pressurized fabric filter collector and testing by Method 5 is required.

Effective date. In accordance with section 111 of the Act, these regulations prescribing standards of performance for ferroalloy production facilities are effective May 4, 1976, and apply to electric submerged arc furnaces and their associated dust-handling equipment, the construction or modification of which was commenced after October 21, 1974.

(Secs. 111 and 114 of the Clean Air Act, amended by Sec. 4(a) of Pub. L. 91-604, 84 Stat. 1678 (42 U.S.C. 1857c-6, 1857c-9).)

Dated: April 23, 1976.

RUSSELL E. TRAIN,
Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. The table of sections is amended by adding subpart Z as follows:

Subpart Z—Standards of Performance for Ferroalloy Production Facilities

Sec.

60.260 Applicability and designation of affected facility.
60.261 Definitions.
60.262 Standard for particulate matter.
60.263 Standard for carbon monoxide.
60.264 Emission monitoring.
60.265 Monitoring of operations.
60.266 Test methods and procedures.

2. Part 60 is amended by adding subpart Z as follows:

Subpart Z—Standards of Performance for Ferroalloy Production

§ 60.260 Applicability and designation of affected facility.

The provisions of this subpart are applicable to the following affected facilities: Electric submerged arc furnaces which produce silicon metal, ferrosilicon, calcium silicon, silicomanganese zirconium, ferrochrome silicon, silvery iron, high-carbon ferrochrome, charge chrome standard ferromanganese, silimanganese, ferromanganese silicon, or calcium carbide; and dust-handling equipment.

§ 60.261 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Electric submerged arc furnace" means any furnace wherein electrical energy is converted to heat energy by transmission of current between electrodes partially submerged in the furnace charge.

(b) "Furnace charge" means any material introduced into the electric submerged arc furnace and may consist of, but is not limited to, ores, slag, carbonaceous material, and limestone.

(c) "Product change" means any change in the composition of the furnace charge that would cause the electric submerged arc furnace to become subject to a different mass standard applicable under this subpart.

(d) "Slag" means the more or less completely fused and vitrified matter separated during the reduction of a metal from its ore.

(e) "Tapping" means the removal of slag or product from the electric submerged arc furnace under normal operating conditions such as removal of metal under normal pressure and movement by gravity down the spout into the ladle.

(f) "Tapping period" means the time duration from initiation of the process of opening the tap hole until plugging of the tap hole is complete.

(g) "Furnace cycle" means the time period from completion of a furnace product tap to the completion of the next consecutive product tap.

(h) "Tapping station" means that general area where molten product or slag is removed from the electric submerged arc furnace.

(i) "Blowing tap" means any tap in which an evaluation of gas forces or projects jets of flame or metal sparks beyond the ladle, runner, or collection hood.

(j) "Furnace power input" means the resistive electrical power consumption of an electric submerged arc furnace as measured in kilowatts.

(k) "Dust-handling equipment" means any equipment used to handle particulate matter collected by the air pollution control device (and located at or near such device) serving any electric submerged arc furnace subject to this subpart.

(l) "Control device" means the air pollution control equipment used to remove particulate matter generated by an electric submerged arc furnace from an effluent gas stream.

(m) "Capture system" means the equipment (including hoods, ducts, fans, dampers, etc.) used to capture or transport particulate matter generated by an affected electric submerged arc furnace to the control device.

(n) "Standard ferromanganese" means that alloy as defined by A.S.T.M. designation A99-66.

(o) "Silicomanganese" means that alloy as defined by A.S.T.M. designation A483-66.

(p) "Calcium carbide" means material containing 70 to 85 percent calcium carbide by weight.

(q) "High-carbon ferrochrome" means that alloy as defined by A.S.T.M. designation A101-66 grades HC1 through HC6.

(r) "Charge chrome" means that alloy containing 52 to 70 percent by weight chromium, 5 to 8 percent by weight carbon, and 3 to 6 percent by weight silicon.

(s) "Silvery iron" means any ferrosilicon, as defined by A.S.T.M. designation 100-69, which contains less than 30 percent silicon.

(t) "Ferrochrome silicon" means that alloy as defined by A.S.T.M. designation A482-66.

(u) "Silicomanganese zirconium" means that alloy containing 60 to 65 percent by weight silicon, 1.5 to 2.5 percent by weight calcium, 5 to 7 percent by weight zirconium, 0.75 to 1.25 percent by weight aluminum, 5 to 7 percent by weight manganese, and 2 to 3 percent by weight barium.

(v) "Calcium silicon" means that alloy as defined by A.S.T.M. designation A495-64.

(w) "Ferrosilicon" means that alloy as defined by A.S.T.M. designation A100-69 grades A, B, C, D, and E which contains 50 or more percent by weight silicon.

(x) "Silicon metal" means any silicon alloy containing more than 96 percent silicon by weight.

(y) "Ferromanganese silicon" means that alloy containing 63 to 66 percent by weight manganese, 28 to 32 percent by weight silicon, and a maximum of 0.08 percent by weight carbon.

§ 60.262 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any electric submerged arc furnace any gases which:

(1) Exit from a control device and contain particulate matter in excess of 0.45 kg/MW-hr (0.99 lb/MW-hr) while silicon metal, ferrosilicon, calcium silicon, or silicomanganese zirconium is being produced.

(2) Exit from a control device and contain particulate matter in excess of 0.23 kg/MW-hr (0.51 lb/MW-hr) while high-carbon ferrochrome, charge chrome, standard ferromanganese, silicomanganese, calcium carbide, ferrochrome silicon, ferromanganese silicon, or silvery iron is being produced.

(3) Exit from a control device and exhibit 15 percent opacity or greater.

(4) Exit from an electric submerged arc furnace and escape the capture system and are visible without the aid of instruments. The requirements under this subparagraph apply only during periods when flow rates are being established under § 60.265(d).

(5) Escape the capture system at the tapping station and are visible without the aid of instruments for more than 40 percent of each tapping period. There are no limitations on visible emissions under this subparagraph when a blowing tap occurs. The requirements under this subparagraph apply only during periods when flow rates are being established under § 60.265(d).

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any dust-handling equipment any gases which exhibit 10 percent opacity or greater.

§ 60.263 Standard for carbon monoxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any electric submerged arc furnace any gases which contain, on a dry basis, 20 or greater volume percent of carbon monoxide. Combustion of such gases under conditions acceptable to the Administrator constitutes compliance with this section. Acceptable conditions include, but are not limited to, flaring of gases or use of gases as fuel for other processes.

§ 60.264 Emission monitoring.

(a) The owner or operator subject to the provisions of this subpart shall install, calibrate, maintain and operate a continuous monitoring system for measurement of the opacity of emissions discharged into the atmosphere from the control device(s).

(b) For the purpose of reports required under § 60.7(c), the owner or operator shall report as excess emissions all six-minute periods in which the average opacity is 15 percent or greater.

(c) The owner or operator subject to the provisions of this subpart shall submit a written report of any product change to the Administrator. Reports of product changes must be postmarked not later than 30 days after implementation of the product change.

§ 60.265 Monitoring of operations.

(a) The owner or operator of any electric submerged arc furnace subject to the provisions of this subpart shall maintain daily records of the following information:

(1) Product being produced.

(2) Description of constituents of furnace charge, including the quantity, by weight.

(3) Time and duration of each tapping period and the identification of material tapped (slag or product.)

(4) All furnace power input data obtained under paragraph (b) of this section.

(5) All flow rate data obtained under paragraph (c) of this section or all fan motor power consumption and pressure drop data obtained under paragraph (e) of this section.

(b) The owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate a device to measure and continuously record the furnace power input. The furnace power input may be measured at the output or input side of the transformer. The device must have an accuracy of ±5 percent over its operating range.

(c) The owner or operator subject to the provisions of this subpart shall install, calibrate, and maintain a monitoring device that continuously measures and records the volumetric flow rate through each separately ducted hood of the capture system, except as provided under paragraph (e) of this section. The owner or operator of an electric submerged arc furnace that is equipped with a water cooled cover which is designed to contain and prevent escape of the generated gas and particulate matter shall monitor only the volumetric flow rate through the capture system for control of emissions from the tapping station. The owner or operator may install the monitoring device(s) in any appropriate location in the exhaust duct such that reproducible flow rate monitoring will result. The flow rate monitoring device must have an accuracy of ±10 percent over its normal operating range and must be calibrated according to the manufacturer's instructions. The Administrator may require the owner or operator to demonstrate the accuracy of the monitoring device relative to Methods 1 and 2 of Appendix A to this part.

(d) When performance tests are conducted under the provisions of § 60.8 of this part to demonstrate compliance with the standards under §§ 60.262(a)(4) and (5), the volumetric flow rate through each separately ducted hood of the capture system must be determined using the monitoring device required under paragraph (c) of this section. The volumetric flow rates must be determined for furnace power input levels at 50 and 100 percent of the nominal rated capacity of the electric submerged arc furnace. At all times the electric submerged arc furnace is operated, the owner or operator shall maintain the volumetric flow rate at or above the appropriate levels for that furnace power input level determined during the most recent performance test. If emissions due to tapping are captured and ducted separately from emissions of the electric submerged arc furnace, during each tapping period the owner or operator shall maintain the exhaust flow rates through the capture system over the tapping station at or above the levels established during the most recent performance test. Operation at lower flow rates may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. The owner or operator may request that these flow rates be reestablished by conducting new performance tests under § 60.8 of this part.

(e) The owner or operator may as an alternative to paragraph (c) of this section determine the volumetric flow rate through each fan of the capture system from the fan power consumption, pressure drop across the fan and the fan performance curve. Only data specific to the operation of the affected electric submerged arc furnace are acceptable for demonstration of compliance with the requirements of this paragraph. The owner or operator shall maintain on file a permanent record of the fan performance curve (prepared for a specific temperature) and shall:

(1) Install, calibrate, maintain, and operate a device to continuously measure and record the power consumption of the fan motor (measured in kilowatts), and

(2) Install, calibrate, maintain, and operate a device to continuously measure and record the pressure drop across the fan. The fan power consumption and pressure drop measurements must be synchronized to allow real time comparisons of the data. The monitoring devices must have an accuracy of ±5 percent over their normal operating ranges.

(f) The volumetric flow rate through each fan of the capture system must be determined from the fan power consumption, fan pressure drop, and fan performance curve specified under paragraph (e) of this section, during any performance test required under § 60.8 of this part to demonstrate compliance with the standards under §§ 60.262(a)(4) and (5). The owner or operator shall determine the volumetric flow rate at a representative temperature for furnace power input levels of 50 and 100 percent of the nominal rated capacity of the electric submerged arc furnace. At all times the electric submerged arc furnace is operated, the owner or operator shall maintain the fan power consumption and fan pressure drop at levels such that the volumetric flow rate is at or above the levels established during the most recent performance test for that furnace power input level. If emissions due to tapping are captured and ducted separately from emissions of the electric submerged arc furnace, during each tapping period the owner or operator shall maintain the fan power consumption and fan pressure drop at levels such that the volumetric flow rate is at or above the levels established during the most recent performance test. Operation at lower flow rates may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. The owner or operator may request that these flow rates be reestablished by conducting new performance tests under § 60.8 of this part. The Administrator may require the owner or operator to verify the fan performance curve by monitoring necessary fan operating parameters and determining the gas volume moved relative to Methods 1 and 2 of Appendix A to this part.

(g) All monitoring devices required under paragraphs (c) and (e) of this section are to be checked for calibration annually in accordance with the procedures under § 60.13(b).

§ 60.266 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.262 and § 60.263 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content except that the heating systems specified in paragraphs 2.1.2 and 2.1.4 of Method 5 are not to be used when the carbon monoxide content of the gas stream exceeds 10 percent by volume, dry basis.

(2) Method 1 for sample and velocity traverses.

(3) Method 2 for velocity and volumetric flow rate.

(4) Method 3 for gas analysis, including carbon monoxide.

(b) For Method 5, the sampling time for each run is to include an integral number of furnace cycles. The sampling time for each run must be at least 60 minutes and the minimum sample volume must be 1.8 dscm (64 dscf) when sampling emissions from open electric submerged arc furnaces with wet scrubber control devices, sealed electric submerged arc furnaces, or semi-enclosed electric submerged arc furnaces. When sampling emissions from other types of installations, the sampling time for each run must be at least 200 minutes and the minimum sample volume must be 5.7 dscm (200 dscf). Shorter sampling times or smaller sampling volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) During the performance test, the owner or operator shall record the maximum open hood area (in hoods with segmented or otherwise moveable sides) under which the process is expected to be operated and remain in compliance with all standards. Any future operation of the hooding system with open areas in excess of the maximum is not permitted.

(d) The owner or operator shall construct the control device so that volumetric flow rates and particulate matter emissions can be accurately determined by applicable test methods and procedures.

(e) During any performance test required under § 60.8 of this part, the owner or operator shall not allow gaseous diluents to be added to the effluent gas stream after the fabric in an open pressurized fabric filter collector unless the total gas volume flow from the collector is accurately determined and considered in the determination of emissions.

(f) When compliance with § 60.263 is to be attained by combusting the gas stream in a flare, the location of the sampling site for particulate matter is to be upstream of the flare.

(g) For each run, particulate matter emissions, expressed in kg/hr (lb/hr), must be determined for each exhaust stream at which emissions are quantified using the following equation:

$$E_n = C_s Q_s$$

where:

E_n = Emissions of particulate matter in kg/hr (lb/hr).

C_s = Concentration of particulate matter in kg/dscm (lb/dscf) as determined by Method 5.

Q_s = Volumetric flow rate of the effluent gas stream in dscm/hr (dscf/hr) as determined by Method 2.

(h) For Method 5, particulate matter emissions from the affected facility, expressed in kg/MW-hr (lb/MW-hr) must be determined for each run using the following equation:

$$E = \frac{\sum_{n=1}^{N} E_n}{p}$$

where:

E = Emissions of particulate from the affected facility, in kg/MW-hr (lb/MW-hr).

N = Total number of exhaust streams at which emissions are quantified.

E_n = Emission of particulate matter from each exhaust stream in kg/hr (lb/hr), as determined in paragraph (g) of this section.

p = Average furnace power input during the sampling period, in megawatts as determined according to § 60.265 (b).

(Secs. 111 and 114 of the Clean Air Act, as amended by sec. 4(a) of Pub. L. 91-604, 84 Stat. 1678 (42 U.S.C. 1857c-6, 1857c-9))

[FR Doc.76-12814 Filed 5-3-76;8:45 am]

34

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 539-5]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCE

Delegation of Authority to Commonwealth of Massachusetts

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the Commonwealth of Massachusetts on January 23, 1976, EPA is today amending 40 CFR 60.4, "Address," to reflect this delegation. A notice announcing this delegation is published in the Notices section of today's FEDERAL REGISTER. The amended § 60.4, which adds the address of the Massachusetts Department of Environmental Quality Engineering, Division of Air Quality Control, to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on January 23, 1976, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended.

42 U.S.C. 1857c-6.

Dated May 3, 1976.

STANLEY W. LEGRO,
Assistant Administrator for Enforcement.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (W) to read as follows:

§ 60.4 Address.

* * * * * * *

(b) * * *

(W) Massachusetts Department of Environmental Quality Engineering, Division of Air Quality Control, 600 Washington Street, Boston, Massachusetts 02111.

[FR Doc.76-13822 Filed 5-12-76;8:45 am]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State of New Hampshire

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of New Hampshire on February 17, 1976, EPA is today amending 40 CFR 60.4, "Address," to reflect this delegation. A Notice announcing this delegation is published in the Notices section of today's FEDERAL REGISTER. The amended § 60.4, which adds the address of the New Hampshire Air Pollution Control Agency to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on February 17, 1976, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended.

42 U.S C. 1857c-6.

Dated: May 3, 1976.

STANLEY W. LEGRO,
Assistant Administrator of Enforcement.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (EE) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(EE) New Hampshire Air Pollution Control Agency, Department of Health and Welfare, State Laboratory Building, Hazen Drive, Concord, New Hampshire 03301.

[FR Doc.76-13821 Filed 5-12-76,8:45 am]

35

[FRL 509-3]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Ferroalloy Production Facilities

Correction

In FR Doc. 76-12814 appearing at page 18498 in the FEDERAL REGISTER of Tuesday, May 4, 1976 the following corrections should be made:

1. On page 18498, second column, last paragraph designated "(1)", second line, fourth word should read "representativeness".

2. On page 18501, first column, the subpart heading immediately preceding the text, should read "Subpart Z—Standards of Performance for Ferroalloy Production Facilities".

3. On page 18501, in § 60.260, second column, fourth line from the top, the third word should read "silicomanga-".

4. On page 18501, second column, in § 60.261 (i), second line, third word should read "evolution".

5. On page 18503, third column, in § 60.266(h) the equation should have appeared as follows:

$$E = \frac{\sum_{n=1}^{N} E_n}{p}$$

[OPP—260019; FRL 545-8]

36

Title 40—Protection of Environment

[FRL 548-4]

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State of California on Behalf of Ventura County and Northern Sonoma County Air Pollution Control Districts

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of California on behalf of the Ventura County Air Pollution Control District and the Northern Sonoma County Air Pollution Control District, dated February 2, 1976, EPA is today amending 40 CFR 60.4, *Address*, to reflect this delegation. A Notice announcing this delegation is published today in the Notice section of this issue. The amended § 60.4 is set forth below. It adds the addresses of the Ventura County and Northern Sonoma County Air Pollution Control Districts, to which must be addressed all reports, requests, applications, submittals, and communications pursuant to this part by sources subject to the NSPS located within these Air Pollution Control Districts.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on Febraury 2, 1976, and it serves no purposes to delay the technical change of this addition of the Air Pollution Control District addresses to the Code of Federal Regulations.

This rulemaking is effective immediately.

(Sec. 111 of the Clean Air Act, as amended [42 U.S.C. 1857c-6]).

Dated: May 3, 1976.

STANLEY W. LEGRO,
Assistant Administrator for Enforcement.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. Section 60.4(b) is amended by revising subparagraph F to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

F California—
Bay Area Air Pollution Control District, 939 Ellis St., San Francisco, CA 94109.
Del Norte County Air Pollution Control District, Courthouse, Crescent City, CA 95531.
Humboldt County Air Pollution Control District, 5600 S. Broadway, Eureka, CA 95501.
Kern County Air Pollution Control District, 1700 Flower St. (P.O. Box 997), Bakersfield, CA 93302.
Monterey Bay Unified Air Pollution Control District, 420 Church St. (P.O. Box 487), Salinas, CA 93901.
Northern Sonoma County Air Pollution Control District, 3313 Chanate Rd., Santa Rosa, CA 95404.
Trinity County Air Pollution Control District, Box AJ, Weaverville, CA 96093
Ventura County Air Pollution Control District, 625 E. Santa Clara St., Ventura, CA 93001.

37

Title 40—Protection of Environment

[FRL 562-8]

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State of Utah

Pursuant to the delegation of authority for the standards of performance for twelve (12) categories of new stationary sources (NSPS) to the State of Utah on May 13, 1976, EPA is today amending 40 CFR 60.4, Address, to reflect this delegation. A Notice announcing this delegation is published today in the FEDERAL REGISTER. The amended § 60.4, which adds the address of the Utah Air Conservation Committee to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on May 13, 1976, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of section 111 of the Clean Air Act, as amended, 42 U.S C. 1857c-6.

Dated: June 10, 1976.

STANLEY W. LEGRO,
Assistant Administrator for Enforcement.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (TT) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(TT)—State of Utah, Utah Air Conservation Committee, State Division of Health, 44 Medical Drive, Salt Lake City, Utah 84113.

* * * * *

[FR Doc.76-17433 Filed 6-14-76;8:45 am]

38 Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 564-6]

NEW SOURCE REVIEW

Delegation of Authority to the State of Georgia

The amendments below institute certain address changes for reports and applications required from operators of new sources. EPA has delegated to the State of Georgia authority to review new and modified sources. The delegated authority includes the reviews under 40 CFR Part 52 for the prevention of significant deterioration. It also includes the review under 40 CFR Part 60 for the standards of performance for new stationary sources and review under 40 CFR Part 61 for national emission standards for hazardous air pollutants.

A notice announcing the delegation of authority is published elsewhere in the Notices section this issue of the FEDERAL REGISTER. These amendments provide that all reports, requests, applications, submittals, and communications previously required for the delegated reviews will now be sent instead to the Environmental Protection Division, Georgia Department of Natural Resources, 270 Washington Street SW., Atlanta, Georgia 30334, instead of EPA's Region IV.

The Regional Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on May 3, 1976, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal regulations.

This rulemaking is effective immediately, and is issued under the authority of Sections 101, 110, 111, 112 and 301 of the Clean Air Act, as amended 42 U.S.C. 1857, 1857C-5, 6, 7 and 1857g.

Dated: June 11, 1976.

JACK E. RAVAN,
Regional Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

DELEGATION OF AUTHORITY TO THE STATE OF GEORGIA

Part 60 of Chapter I, Title 40, Code of Federal Regulations, is amended as follows:

2. In § 60.4, paragraph (b)(L) is revised to read as follows:

§ 60.4 Address.

* * * * * *

(b) * * *

(L) State of Georgia, Environmental Protection Division, Department of Natural Resources, 270 Washington Street, S.W., Atlanta, Georgia 30334.

39

SUBCHAPTER C—AIR PROGRAMS

[FRL 574-3]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State of California on Behalf of Fresno, Mendocino, San Joaquin, and Sacramento County Air Pollution Control Districts

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of California on behalf of the Fresno County Air Pollution Control District, the Mendocino County Air Pollution Control District, the San Joaquin County Air Pollution Control District, and the Sacramento County Air Pollution Control District, dated March 29, 1976, EPA is today amending 40 CFR 60.4, *Address*, to reflect this delegation. A Notice announcing this delegation is published today in the Notice Section of this issue. The amended § 60.4 is set forth below. It adds the addresses of the Fresno County, Mendocino County, San Joaquin County, and Sacramento County Air Pollution Control Districts, to which must be addressed all reports, requests, applications, submittals, and communications pursuant to this part by sources subject to the NSPS located within these Air Pollution Control Districts.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on March 29, 1976, and it serves no purpose to delay the technical change of this addition of the Air Pollution Control District addresses to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of section 111 of the Clean Air Act, as amended [42 U.S.C. 1857c-6].

Dated: June 15, 1976.

STANLEY W. LEGRO,
Assistant Administrator for Enforcement.

Part 60 of Chapter I, Title 40, of the Code of Federal Regulations, is amended as follows:

1. In § 60.4, paragraph (b) is amended by revising subparagraph F to read as follows:

§ 60.4 Address.

* * * * * *

(b) * * *

(A)-(E) * * *

(F) California:

Bay Area Air Pollution Control District, 939 Ellis St., San Francisco, CA 94109
Del Norte County Air Pollution Control District, Courthouse, Crescent City, CA 95531
Fresno County Air Pollution Control District, 515 S. Cedar Ave., Fresno, CA 93702
Humboldt County Air Pollution Control District, 5600 S. Broadway, Eureka, CA 95501
Kern County Air Pollution Control District, 1700 Flower St. (P.O. Box 997), Bakersfield, CA 93302
Mendocino County Air Pollution Control District, County Courthouse, Ukiah, CA 95482
Monterey Bay Unified Air Pollution Control District, 420 Church St. (P.O. Box 487), Salinas, CA 93901
Northern Sonoma County Air Pollution Control District, 3313 Chanate Rd., Santa Rosa, CA 95404
Sacramento County Air Pollution Control District, 2221 Stockton Blvd., Sacramento, CA 95827
San Joaquin County Air Pollution Control District, 1601 E. Hazelton St. (P.O. Box 2009), Stockton, CA 95201
Trinity County Air Pollution Control District, Box AJ, Weaverville, CA 96093
Ventura County Air Pollution Control District, 625 E. Santa Clara St., Ventura, CA 93001

40 Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 597-1]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State of California on Behalf of Madera County Air Pollution Control District

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of California on behalf of the Madera County Air Pollution Control District, dated May 12, 1976, EPA is today amending 40 CFR 60.4 *Address*, to reflect this delegation. A Notice announcing this delegation is published in the Notices Section of this issue of the FEDERAL REGISTER, Environmental Protection Agency, FRL 596-8. The amended § 60.4 is set forth below. It adds the address of the Madera County Air Pollution Control District, to which must be addressed all reports, requests, applications, submittals, and communications pursuant to this part by sources subject to the NSPS located within this Air Pollution Control District.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on May 12, 1976, and it serves no purpose to delay the technical change of this addition of the Air Pollution Control District address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended [42 U.S.C. 1857c-6].

Dated: July 27, 1976.

PAUL DEFALCO,
Regional Administrator,
Region IX, EPA.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph F to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

F—CALIFORNIA

Bay Area Air Pollution Control District, 939 Ellis St., San Francisco, CA 94109
Del Norte County Air Pollution Control District, Courthouse, Crescent City, CA 95531
Fresno County Air Pollution Control District, 515 S. Cedar Avenue, Fresno, CA 93702
Humboldt County Air Pollution Control District, 5600 S. Broadway, Eureka, CA 95501
Kern County Air Pollution Control District, 1700 Flower St. (P.O. Box 997), Bakersfield, CA 93302
Madera County Air Pollution Control District, 135 W. Yosemite Avenue, Madera, CA 93637
Mendocino County Air Pollution Control District, County Courthouse, Ukiah, CA 95482
Monterey Bay Unified Air Pollution Control District, 420 Church St. (P.O. Box 487), Salinas, CA 93901
Northern Sonoma County Air Pollution Control District, 3313 Chanate Rd., Santa Rosa, CA 95404
Sacramento County Air Pollution Control District, 2221 Stockton Blvd., Sacramento, CA 95827
San Joaquin County Air Pollution Control District, 1601 E. Hazelton St. (P.O. Box 2009), Stockton, CA 95201
Trinity County Air Pollution Control District, Box AJ, Weaverville, CA 96093
Ventura County Air Pollution Control District, 625 E. Santa Clara St., Ventura, CA 93001

* * * * *

[FR Doc.76-23146 Filed 8-6-76,8:45 am]

FEDERAL REGISTER, VOL. 41, NO. 154

MONDAY, AUGUST 9, 1976

41 Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 600-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCE

Delegation of Authority to the U.S. Virgin Islands

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the U.S. Virgin Islands on June 30, 1976, EPA is today amending 40 CFR 60.4, Address, to reflect this delegation. A Notice announcing this delegation is published at page 34685 of today's FEDERAL REGISTER. The amended § 60.4, which adds the address of the U.S. Virgin Islands, Department of Conservation and Cultural Affairs, to which reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on June 30, 1976, and it serves no purpose to delay the technical change of this addition of the U.S. Virgin Islands address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended.

(42 U.S.C. 1857c-6)

Dated: August 4, 1976.

GERALD M. HANSLER,
Regional Administrator,
Region II.

1. In § 60.4 paragraph (b) is amended by revising subparagraph (CCC) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(BBB) * * *

(CCC)—U.S. Virgin Islands: U.S. Virgin Islands Department of Conservation and Cultural Affairs, P.O. Box 578, Charlotte Amalie, St. Thomas, U.S. Virgin Islands 00801.

[FR Doc.76-23898 Filed 8-13-76;8:45 am]

FEDERAL REGISTER, VOL. 41, NO. 159

MONDAY, AUGUST 16, 1976

42 [FRL 598-2]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Revision to Emission Monitoring Requirements

On October 6, 1975 (40 FR 46250), under section 111 of the Clean Air Act, as amended, the Environmental Protection Agency (EPA) promulgated emission monitoring requirements and revisions to the performance testing methods in 40 CFR Part 60. The provisions of § 60.13(i) allow the Administrator to approve alternatives to monitoring procedures or requirements only upon written application by an owner or operator of an affected facility; monitoring equipment manufacturers would not be allowed to apply for approval of alternative monitoring equipment. Since EPA did not intend to prevent monitoring equipment manufacturers from applying for approval of alternative monitoring equipment, § 60.13(i) is being revised. As revised, any person will be allowed to make application to the Administrator for approval of alternative monitoring procedures or requirements.

This revision does not add new requirements, rather it provides greater flexibility for approval of alternative equipment and procedures. This revision is effective (date of publication).

(Sections 111, 114, and 301(a) of the Clean Air Act, as amended by sec. 4(a) of Pub. L. 91-604, 84 Stat. 1678 and by sec. 15(c)(2) of Pub. L. 91-604, 84 Stat. 1713 (42 U.S.C. 1857c-6, 1857c-9, and 1857g(a)).)

Dated: August 13, 1976.

RUSSELL E. TRAIN,
Administrator.

In 40 CFR Part 60, Subpart A is amended as follows:

1. Section 60.13 is amended by revising paragraph (i) as follows:

§ 60.13 Monitoring requirements.

* * * * *

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

* * * * *

[FR Doc.76-24558 Filed 8-19-76;8:45 am]

FEDERAL REGISTER, VOL. 41, NO. 163

FRIDAY, AUGUST 20, 1976

43

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

5. By revising § 60.9 to read as follows:

§ 60.9 Availability of information.

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this Part shall be governed by Part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§ 60.5 and 60.6 is governed by § 2.201 through § 2.213 of this chapter and not by § 2.301 of this chapter.)

FEDERAL REGISTER, VOL. 41, NO. 171

WEDNESDAY, SEPTEMBER 1, 1976

44 Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 617-2]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State of California on Behalf of Stanislaus County Air Pollution Control District; Delegation of Authority to State of California on Behalf of Sacramento County Air Pollution Control District; Correction

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of California on behalf of the Stanislaus County Air Pollution Control District, dated July 2, 1976, EPA is today amending 40 CFR 60.4 *Address*, to reflect this delegation. A notice announcing this delegation is published today at 41 FR 40108. The amended § 60.4 is set forth below. It adds the address of the Stanislaus County Air Pollution Control District, to which must be addressed all reports, requests, applications, submittals, and communications pursuant to this part by sources subject to the NSPS located within this Air Pollution Control District.

On July 8, 1976, EPA amended 40 CFR 60.4, *Address* to reflect delegation of authority for NSPS to the State of California on behalf of the Sacramento County Air Pollution Control District. By letter of July 30, 1976, Colin T. Greenlaw, M.D., Sacramento County Air Pollution Control Officer, notified EPA that the address published at 41 FR 27967 was incorrect. Therefore, EPA is today also amending 40 CFR 60.4, *Address* to reflect the correct address for the Sacramento County Air Pollution Control District.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegations which are reflected by this administrative amendment were effective on July 2, 1976 and March 29, 1976, and it serves no purpose to delay the technical change of these additions of the Air Pollution Control Districts addresses to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended (42 U.S.C. 1857c-6)

Dated: September 8, 1976.

L. RUSSELL FREEMAN,
Acting Regional Administrator, Region IX, EPA.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b)(f) is revised to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(F) California:

Bay Area Air Pollution Control District, 939 Ellis St., San Francisco, CA 94109
Del Norte County Air Pollution Control District, Courthouse, Crescent City, CA 95531
Fresno County Air Pollution Control District, 515 S. Cedar Avenue, Fresno, CA 93702
Humboldt County Air Pollution Control District, 5600 S. Broadway, Eureka, CA 95501
Kern County Air Pollution Control District, 1700 Flower St. (P.O. Box 997), Bakersfield, CA 93302
Madera County Air Pollution Control District, 135 W. Yosemite Avenue, Madera, CA 93637
Mendocino County Air Pollution Control District, County Courthouse, Ukiah, CA 95482
Monterey Bay Unified Air Pollution Control District, 420 Church St. (P.O. Box 487), Salinas, CA 93901
Northern Sonoma County Air Pollution Control District, 3313 Chanate Rd., Santa Rosa, CA 95404
Sacramento County Air Pollution Control District, 3701 Branch Center Road, Sacramento, CA 95827
San Joaquin County Air Pollution Control District, 1601 E. Hazelton St. (P.O. Box 2009), Stockton, CA 95201
Stanislaus County Air Pollution Control District, 820 Scenic Drive, Modesto, CA 95350
Trinity County Air Pollution Control District, Box AJ, Weaverville, CA 96093
Ventura County Air Pollution Control District, 625 E. Santa Clara St., Ventura, CA 93001

* * * * *

[FR Doc.76-27175 Filed 9-16-76;8:45 am]

FEDERAL REGISTER, VOL. 41, NO. 182

FRIDAY, SEPTEMBER 17, 1976

45 Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 619-1]

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

Reports and Applications From Operators of New Sources; Address Changes

DELEGATION OF AUTHORITY TO THE STATE OF ALABAMA

The amendments below institute certain address changes for reports and applications required from operators of new sources. EPA has delegated to the State of Alabama authority to review new and modified sources. The delegated authority includes the review under 40 CFR Part 60 for the standards of performance for new stationary sources and review under 40 CFR Part 61 for national emission standards for hazardous air pollutants.

A notice announcing the delegation of authority is published elsewhere in this issue of the FEDERAL REGISTER. These amendments provide that all reports, requests, applications, submittals, and communications previously reuired for the delegated reviews will now be sent instead to the Air Pollution Control Division, Alabama Air Pollution Control Commission, 645 South McDonough Street, Montgomery, Alabama 36104, instead of EPA's Region IV.

The Regional Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on August 5, 1976, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of sections 111, 112, and 301 of the Clean Air Act, as amended 42 U.S.C. 1857, 1857c-5, 6, 7 and 1857g.

Dated: September 9, 1976.

JACK E. LAVAN,
Regional Administrator.

Part 60 of Chapter I, Title 40, Code of Federal Regulations, is amended as follows:

1. In § 60.4, paragraph (b) is amended by revising subparagraph (B) to read as follows:

§ 60.4 Address.

* * * * * *

(b) * * *

(B) State of Alabama, Air Pollution Control Division, Air Pollution Control Commission, 645 S. McDonough Street, Montgomery, Alabama 36104.

46 Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 623-7]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to the State of Indiana

Pursuant to the delegation of authority to implement the standards of performance for new stationary sources (NSPS) to the State of Indiana on April 21, 1976, EPA is today amending 40 CFR 60.4, *Address*, to reflect this delegation. A notice announcing this delegation is published Thursday, September 30, 1976 (41 FR 43237). The amended § 60.4, which adds the address of the Indiana Air Pollution Control Board to that list of addresses to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must be sent, is set forth below.

The Administrator finds good cause for foregoing prior notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on April 21, 1976, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately.

(Sec 111 of the Clean Air Act, as amended, 42 U.S.C. 1857c-6.)

Dated: September 22, 1976.

GEORGE R. ALEXANDER, Jr.,
Regional Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4, paragraph (b) is amended by revising subparagraph P, to read as follows:

§ 60.4 Address.

* * * * * *

(b) * * *

(A)-(O) * * *

(P) State of Indiana, Indiana Air Pollution Control Board, 1330 West Michigan Street, Indianapolis, Indiana 46206.

* * * * * *

[FR Doc 76-28507 Filed 9-29-76,8:45 am]

47 Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 629-8]

PART 60—STANDARDS OF PERFORMANCE FOR STATIONARY SOURCES

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

Delegation of Authority to State of North Dakota

Pursuant to the delegation of authority for the standards of performance for new sources (NSPS) and national emission standards for hazardous air pollutants (NESHAPS) to the State of North Dakota on August 30, 1976, EPA is today amending respectively 40 CFR 60.4 and 61.04 Address, to reflect this delegation. A notice announcing this delegation is published today in the notices section The amended §§ 60.4 and 61.04 which add the address of the North Dakota State Department of Health to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to these parts must also be addressed, are set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on August 30, 1976, and it serves no purpose to delay the technical change of this addition to the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of sections 111 and 112 of the Clean Air Act, as amended, (42 U.S.C. 1857c-6 and -7).

Dated: October 1, 1976.

JOHN A. GREEN,
Regional Administrator.

Parts 60 and 61 of Chapter I, Title 40 of the Code of Federal Regulations are respectively amended as follows:

1. In § 60.4, paragraph (b) is amended by revising subparagraph (JJ) to read as follows:

§ 60.4 Address.

* * * * * *

(b) * * *

(A)-(Z) * * *

(AA)-(II) * * *

(JJ)—State of North Dakota, State Department of Health, State Capitol, Bismarck, North Dakota 58501.

48

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 638-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State of California On Behalf of Santa Barbara County Air Pollution Control District

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of California on behalf of the Santa Barbara County Air Pollution Control District, dated September 17, 1976, EPA is today amending 40 CFR 60.4 Address, to reflect this delegation. A Notice announcing this delegation is published in the Notices section of this issue of the FEDERAL REGISTER. The amended § 60.4 is set forth below. It adds the address of the Santa Barbara County Air Pollution Control District, to which must be addressed all reports, requests, applications, submittals, and communications pursuant to this part by sources subject to the NSPS located within this Air Pollution Control District.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected this administrative amendment was effective on **September 17, 1976 and it serves no purpose** to delay the technical change on this addition of the Air Pollution Control District's address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of section 111 of the Clean Air Act, as amended (42 U.S.C. 1857c-6).

Dated: October 20, 1976.

PAUL DE FALCO, JR.,
Regional Administrator,
EPA, Region IX.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b)(3) is amended by revising subparagraph F to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *
(3) * * *
(A)-(E) * * *

F—CALIFORNIA

Bay Area Air Pollution Control District, 939 Ellis St., San Francisco, CA 94109

Del Norte County Air Pollution Control District, Courthouse, Crescent City, CA 95531

Fresno County Air Pollution Control District, 515 S. Cedar Avenue, Fresno, CA 93702.

Humboldt County Air Pollution Control District, 5600 S. Broadway, Eureka, CA 95501.

Kern County Air Pollution Control District, 1700 Flower St. (P.O. Box 997), Bakersfield, CA 93302.

Madera County Air Pollution Control District, 135 W. Yosemite Avenue, Madera, CA 93637.

Mendocino County Air Pollution Control District, County Courthouse, Ukiah, CA 95482.

Monterey Bay Unified Air Pollution Control District, 420 Church St. (P.O. Box 487), Salinas, CA 93901.

Northern Sonoma County Air Pollution Control District, 3313 Chanate Rd., Santa Rosa, CA 95404.

Sacramento County Air Pollution Control District, 3701 Branch Center Road, Sacramento, CA 95827

San Joaquin County Air Pollution Control District, 1601 E. Hazelton St. (P.O. Box 2009), Stockton, CA 95201

Santa Barbara County Air Pollution Control District, 4440 Calle Real, Santa Barbara, CA 93110

Stanislaus County Air Pollution Control District, 820 Scenic Drive, Modesto, CA 95350.

Trinity County Air Pollution Control District, Box AJ, Weaverville, CA 96093.

Ventura County Air Pollution Control District, 625 E Santa Clara St., Ventura, CA 93001

* * * * *

[FR Doc.76-32104 Filed 11-2-76;8:45 am]

FEDERAL REGISTER, VOL. 41, NO. 213

WEDNESDAY, NOVEMBER 3, 1976

49

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 639-3]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Amendments to Subpart D

Standards of performance for fossil fuel-fired steam generators of more than 73 megawatts (250 million Btu per hour) heat input rate are provided under Subpart D of 40 CFR Part 60. Subpart D is amended herein to revise the application of the standards of performance for facilities burning wood residues in combination with fossil fuel.

Subpart D contains standards for particulate matter, sulfur dioxide, nitrogen oxides, and visible emissions from steam generators. These standards, except for the one applicable to visible emissions, are based on heat input. For sulfur dioxide, there are separate standards for liquid fossil fuel-fired and solid fossil fuel-fired facilities with provisions for a prorated standard when combinations of different fossil fuels are fired. There is no sulfur dioxide standard for gaseous fossil fuel-fired facilities since they emit negligible amounts of sulfur dioxide.

To date, there have been two ways for a source owner or operator to comply with the sulfur dioxide standard: (1) By firing low sulfur fossil fuels or (2) by using flue gas desulfurization systems. Complying with the standard by firing low sulfur fossil fuel requires an adequate supply of fuel with a sulfur content low enough to meet the standard. However, it would be possible for the owner or operator to fire, for example, a relatively high sulfur fossil fuel with a very low sulfur fossil fuel (e.g. natural gas) to obtain a fuel mixture which would meet the standard. The low sulfur fuel adds to the heat input but not to the sulfur dioxide emissions and, thereby, has an overall fuel sulfur reduction effect. In the past, the application of Subpart D permitted the heat content of fossil fuels but not wood residue to be used in determining compliance with the standards for particulate matter, sulfur dioxide and nitrogen oxides; the amendment made herein will allow the heat content of wood residue to be used for determining compliance with the standards. The amendment does not change the scope of applicability of Subpart D; all steam generating units constructed after August 17, 1971, and capable of firing fossil fuel at a heat input rate of more than 73 megawatts (250 million Btu per hour) are subject to Subpart D.

RATIONALE FOR THE AMENDMENTS

Wood residue, which includes bark, sawdust, chips, etc., is not a fossil fuel and thus has not been allowed for use as a dilution agent in complying with the sulfur dioxide standard for steam generators. Several companies have requested that EPA revise Subpart D to permit blending of wood residue with high sulfur fossil fuels. This would enable them to obtain a fuel mixture low enough in sulfur to comply with the sulfur dioxide standard. Since Subpart D allows the blending of high and low sulfur fossil fuels, EPA has concluded that it is reasonable to extend application of this principle to wood residue which, although not a fossil fuel, does have low sulfur content.

Several companies have expressed interest in constructing steam generators which continuously fire wood residue in combination with fossil fuel. New facilities will comply with the standards for less cost than at present because they will be able to use wood residue, a valuable source of energy, as an alternative to expense low sulfur fossil fuels. Also, using wood residue as a fuel supplement instead of low sulfur fossil fuels will re-

sult in substantial savings in the consumption of scarce natural gas and oil resources, and will relieve what would otherwise be a substantial solid waste disposal problem. Consumption of energy and raw material resources will be reduced further by minimizing the need for flue gas desulfurization systems at new facilities. There will be no adverse environmental impact; neither sulfur dioxide nor nitrogen oxides emissions will increase as a result of this action. Considering the beneficial, environmental, energy, and economic impacts, it is reasonable to permit wood residue to be fired as a low sulfur fuel to aid in compliance with the standards for fossil fuel-fired steam generators.

In making this amendment, EPA recognizes that affected facilities which burn substantially more wood residue than fossil fuel may have difficulty complying with the 43 nanogram per joule standard for particulate matter (0.1 pound per million Btu). There is not sufficient information available at this time to determine what level of particulate matter emissions is achievable; however, EPA is continuing to gather information on this question. If EPA determines that the particulate matter standard is not achievable, appropriate changes will be made to the standard. Any change would be proposed for public comment; however, in the interim, owners and operators will be subject to the 43 nanogram per joule standard.

'F' Factor Determination

New facilities firing wood residue in combination with fossil fuel will be subject to the emission and fuel monitoring requirements of § 60.45 (as revised on October 6, 1975, 40 FR 46250). The 'F' factors listed in § 60.45(f)(4), which are used for converting continuous monitoring data and performance test data into units of the standard, presently apply only to fossil fuels. Therefore, 'F' factors for bark and wood residue have been added to § 60.45(f)(4). Any owner or operator who elects to calculate his own 'F' factor must obtain approval of the Administrator.

International System of Units

In accordance with the objective to implement national use of the metric system, EPA presents numerical values in both metric units and English units in its regulations and technical publications. In an effort to simplify use of the metric units of measurements, EPA now uses the International System of Units (SI) as set forth in a publication by the American Society for Testing and Materials entitled "Standard for Metric Practice" (Designation: E 380-76). The following amendments to Subpart D reflect the use of SI units.

Miscellaneous

Since these amendments are expected to have limited applicability, no environmental impact statement is required for this rulemaking pursuant to section 1(b) of the "Procedures for the Voluntary Preparation of Environmental Impact Statements" (39 FR 37419).

This action is effective on November 22, 1976. The Agency finds that good cause exists for not publishing this action as a notice of proposed rulemaking and for making it effective immediately upon publication because:

1. The action is expected to have limited applicability.

2. The action will remove an existing restriction on operations without increasing emissions and will have beneficial environmental, energy, and economic effects.

3. The action is not technically controversial and does not alter the overall substantive content of Subpart D.

4. Immediate effectiveness of the action will enable affected parties to proceed promptly and with certainty in conducting their affairs.

(Secs. 111, 114 and 301(a) of the Clean Air Act, as amended by section 4(a) of Pub.L. 91-604, 84 Stat 1678, and by section 15(c)(2) of Pub L. 91-604, 84 Stat. 1713 (42 U.S.C. 1857c-6, 1857c-9, 1857g(a)).)

Date: November 15, 1976.

JOHN QUARLES,
Acting Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. Section 60.40 is amended by revising the designation of affected facility and by substituting the International System (SI) of Units as follows:

§ 60.40 Applicability and designation of affected facility.

(a) The affected facilities to which the provisions of this subpart apply are:

(1) Each fossil fuel-fired steam generating unit of more than 73 megawatts heat input rate (250 million Btu per hour).

(2) Each fossil fuel and wood residue-fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 megawatts (250 million Btu per hour).

(b) Any change to an existing fossil fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.

2. Section 60.41 is amended by adding paragraphs (d) and (e) as follows:

§ 60.41 Definitions.

* * * * *

(d) "Fossil fuel and wood residue-fired steam generating unit" means a furnace or boiler used in the process of burning fossil fuel and wood residue for the purpose of producing steam by heat transfer.

(e) "Wood residue" means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.

3. Section 60.42 is amended by revising paragraph (a)(1) and by substituting SI units in paragraph (a)(1) as follows:

§ 60.42 Standard for particulate matter.

(a) * * *

(1) Contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel or fossil fuel and wood residue.

* * * * *

4. Section 60.43 is amended by revising paragraphs (a)(1) and (a)(2), by substituting SI units in paragraphs (a)(1) and (a)(2), and by revising the formula in paragraph (b) as follows:

§ 60.43 Standard for sulfur dioxide.

(a) * * *

(1) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.

(2) 520 nanograms per joule heat input (1.2 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue.

(b) When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{SO_2} = \frac{y(340) + z(520)}{y + z}$$

where:

PS_{SO_2} is the prorated standard for sulfur dioxide when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired,

y is the percentage of total heat input derived from liquid fossil fuel, and

z is the percentage of total heat input derived from solid fossil fuel.

* * * * *

5. Section 60.44 is amended by revising paragraphs (a)(1), (a)(2), and (a)(3); by substituting SI units in paragraphs (a)(1), (a)(2), and (a)(3); and by revising paragraph (b) as follows:

§ 60.44 Standard for nitrogen oxides.

(a) * * *

(1) 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel or gaseous fossil fuel and wood residue.

(2) 130 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.

(3) 300 nanograms per joule heat input (0.70 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

(b) When different fossil fuels are burned simultaneously in any combination, the applicable standards (in ng/J) shall be determined by proration. Compliance shall be determined by using the following formula:

$$PS_{NO_x}=\frac{x(86)+y(130)+z(300)}{x+y+z}$$

where:

PS_{NO_x} is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired,

x is the percentage of total heat input derived from gaseous fossil fuel,

y is the percentage of total heat input derived from liquid fossil fuel, and

z is the percentage of total heat input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

When lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse is burned in combination with gaseous, liquid, other solid fossil fuel, or wood residue, the standard for nitrogen oxides does not apply.

6. Section 60.45 is amended by substituting SI units in paragraphs (e), (f)(1), (f)(2), (f)(4)(i), (f)(4)(ii), (f)(4)(iii), (f)(4)(iv), (f)(5), and (f)(5)(ii), by adding paragraphs (f)(4)(v) and (f)(5)(iii), and by revising paragraph (f)(6) as follows:

§ 60.45 Emission and fuel monitoring.

* * * * *

(e) An owner or operator required to install continuous monitoring systems under paragraphs (b) and (c) of this section shall for each pollutant monitored use the applicable conversion procedure for the purpose of converting continuous monitoring data into units of the applicable standards (nanograms per joule, pounds per million Btu) as follows:

* * * * *

(f) * * *

(1) E=pollutant emissions, ng/J (lb/million Btu).

(2) C=pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where M=pollutant molecular weight, g/g-mole (lb/lb-mole). M=64.07 for sulfur dioxide and 46.01 for nitrogen oxides.

* * * * *

(4) * * *

(i) For anthracite coal as classified according to A.S.T.M. D 388-66, $F=2.723\times10^{-7}$ dscm/J (10,140 dscf/million Btu) and $F_c=0.532\times10^{-7}$ scm CO_2/J (1,980 scf CO_2/million Btu).

(ii) For subbituminous and bituminous coal as classified according to A.S.T.M. D 388-66, $F=2.637\times10^{-7}$ dscm/J (9,820 dscf/million Btu) and $F_c=0.486\times10^{-7}$ scm CO_2/J (1,810 scf CO_2/million Btu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, $F=2.476\times10^{-7}$ dscm/J (9,220 dscf/million Btu) and $F_c=0.384$ scm CO_2/J (1,430 scf CO_2/million Btu).

(iv) For gaseous fossil fuels, $F=2.347\times10^{-7}$ dscm/J 8,740 dscf/million Btu). For natural gas, propane, and butane fuels, $F_c=0.279\times10^{-7}$ scm CO_2/J (1,040 scf CO_2/million Btu) for natural gas, 0.322×10^{-7} scm CO_2/J (1,200 scf CO_2/million Btu) for propane, and 0.338×10^{-7} scm CO_2/J (1,260 scf CO_2/million Btu) for butane.

(v) For bark F=1.076 dscm/J (9,575 dscf/million Btu) and F_c=0.217 dscm/J (1,927 dscf/million Btu). For wood residue other than bark F=1.038 dscm/J (9,233 dscf/million Btu) and F_c=0.207 dscm/J (1,842 dscf/million Btu).

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/million Btu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or F_c factor (scm CO_2/J, or scf CO_2/million Btu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:

$$F=\frac{227.0(\%H)+95.7(\%C)+35.4(\%S)+8.6(\%N)-28.5(\%O)}{GCV}$$

(SI units)

$$F=\frac{10^{6}[3.64(\%H)+1.53(\%C)+0.57(\%S)+0.14(\%N)-0.46(\%O)]}{GCV}$$

(English units)

$$F_c=\frac{20.0(\%C)}{GCV}$$

(SI units)

$$F_c=\frac{321\times10^{3}(\%C)}{GCV}$$

(English units)

(i) * * *

(ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted, determined by the A.S.T.M. test methods D 2015-66(72) for solid fuels and D 1826-64(70) for gaseous fuels as applicable.

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or F_c value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or F_c factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F=\sum_{i=1}^{n}X_iF_i \text{ or } F_c=\sum_{i=1}^{n}X_i(F_c)_i$$

where:

X_i=the fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.)

F_i or $(F_c)_i$=the applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section.

n=the number of fuels being burned in combination.

* * * * *

7. Section 60.46 is amended by substituting SI units in paragraphs (b) and (f) and paragraph (g) is revised as follows:

§ 60.46 Test methods and procedures.

* * * * *

(b) For Method 5, Method 1 shall be used to select the sampling site and the number of traverse sampling points. The sampling time for each run shall be at least 60 minutes and the minimum sampling volume shall be 0.85 dscm (30 dscf) except that smaller sampling times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator. The probe and filter holder heating systems in the sampling train shall be set to provide a gas temperature no greater than 433 K (320°F).

* * * * *

(f) For each run using the methods specified by paragraphs (a)(3), (a)(4), and (a)(5) of this section, the emissions expressed in ng/J (lb/million Btu) shall be determined by the following procedure:

$$E=CF\frac{20.9}{20.9-\text{percent } O_2}$$

where:

(1) E=pollutant emission ng/J (lb/million Btu).

(2) C=pollutant concentration, ng/dscm (lb/ dscf), determined by method 5, 6, or 7.

(3) Percent O_2=oxygen content by volume (expressed as percent), dry basis. Percent oxygen shall be determined by using the integrated or grab sampling and analysis procedures of Method 3 as applicable.

The sample shall be obtained as follows:

* * * * *

(g) When combinations of fossil fuels or fossil fuel and wood residue are fired, the heat input, expressed in watts (Btu/hr), is determined during each testing period by multiplying the gross calorific value of each fuel fired (in J/kg or Btu/lb) by the rate of each fuel burned (in kg/sec or lb/hr). Gross calorific values are determined in accordance with A.S.T.M methods D 2015-66(72) (solid fuels), D 240-64(73) (liquid fuels), or D 1826-64(7) (gaseous fuels) as applicable. The method used to determine calorific value of wood residue must be approved by the Administrator. The owner or operator shall determine the rate of fuels burned during each testing period by suitable methods and shall confirm the

rate by a material balance over the steam generation system.

(Sections 111, 114, and 301(a) of the Clean Air Act as amended by section 4(a) of Pub L. 91-604, 84 Stat. 1678 and by section 15(c)(2) of Pub. L. 91-604, 84 Stat. 1713 (42 U.S.C. 1857c-6, 1857c-9, 1857g(a)).

[FR Doc.76-33966 Filed 11-19-76;8:45 am]

50 Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 639-2]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Amendments to Reference Methods 13A and 13B

On August 6, 1975 (40 FR 33151), the Environmental Protection Agency (EPA) Promulgated Reference Methods 13A and 13B in Appendix A to 40 CFR Part 60. Methods 13A and 13B prescribe testing and analysis procedures for fluoride emissions from stationary sources. After promulgation of the methods, EPA continued to evaluate them and as a result has determined the need for certain amendments to improve the accuracy and precision of the methods.

Methods 13A and 13B require assembly of the fluoride sampling train so that the filter is located either between the third and fourth impingers or in an optional location between the probe and first impinger. They also specify that a fritted glass disc be used to support the filter. Since promulgation of the methods, EPA has found that when a glass frit filter support is used in the optional filter location, some of the fluoride sample is retained on the glass. Although no tests have been performed, it is believed that fluoride retention may also occur if a sintered metal frit filter support is used. However, in tests performed using a 20 mesh stainless steel screen as a filter support no fluoride retention was noted. Therefore, to eliminate the possibility of fluoride retention, sections 5.1.5 and 7.1.3 of Methods 13A and 13B are being revised to require the use of a 20 mesh stainless steel screen filter support if the filter is located between the probe and first impinger. If the filter is located in the normal position between the third and fourth impingers, the glass frit filter support may still be used.

In addition to the changes to sections 5.1.5 and 7.1.3, a few corrections are also being made. The amendments promulgated herein are effective on November 29, 1976. EPA finds that good cause exists for not publishing this action as a notice of proposed rulemaking and for making it effective immediately upon publication because:

1. The action is intended to improve the accuracy and precision of Methods 13A and 13B and does not alter the overall substantive content of the methods or the stringency of standards of performance for fluoride emissions.

2. The amended methods may be used immediately in source testing for fluoride emissions.

Dated: November 17, 1976.

JOHN QUARLES,
Acting Administrator.

In Part 60 of Chapter I, Title 40 of the Code of Federal Regulations, Appendix A is amended as follows:

1. Reference Method 13A is amended as follows:

(a) In section 3., the phrase "300 μg/liter" is corrected to read "300 mg/liter" and the parenthetical phrase "(see section 7.3.6)" is corrected to read "(see section 7.3.4)".

(b) Section 5.1.5 is revised to read as follows:

5.1.5 Filter holder—If located between the probe and first impinger, borosilicate glass with a 20 mesh stainless steel screen filter support and a silicone rubber gasket; neither a glass frit filter support nor a sintered metal filter support may be used if the filter is in front of the impingers. If located between the third and fourth impingers, borosilicate glass with a glass frit filter support and a silicone rubber gasket. Other materials of construction may be used with approval from the Administrator, e g., if probe liner is stainless steel, then filter holder may be stainless steel. The holder design shall provide a positive seal against leakage from the outside or around the filter.

(c) Section 7.1.3 is amended by revising the first two sentences of the sixth paragraph to read as follows:

7 1.3 Preparation of collection train. • • •
Assemble the train as shown in Figure 13A-1 with the filter between the third and fourth impingers. Alternatively, the filter may be placed between the probe and first impinger if a 20 mesh stainless steel screen is used for the filter support. • • •

• • • • •

(d) In section 7.3.4, the reference in the first paragraph to "section 7.3.6" is corrected to read "section 7.3.5".

2. Reference Method 13B is amended as follows:

(a) In the third line of section 3, the phrase "300μg/liter" is corrected to read "300 mg/liter".

(b) Section 5.1.5 is revised to read as follows:

5 1.5 Filter holder—If located between the probe and first impinger, borosilicate glass with a 20 mesh stainless steel screen filter support and a silicone rubber gasket; neither a glass frit filter support nor a sintered metal filter support may be used if the filter is in front of the impingers. If located between the third and fourth impingers, borosilicate glass with a glass frit filter support and a silicone rubber gasket. Other materials of construction may be used with approval from the Administrator, e g., if probe liner is stainless steel, then filter holder may be stainless steel. The holder design shall provide a positive seal against leakage from the outside or around the filter.

(c) Section 7.1.3 is amended by revising the first two sentences of the sixth paragraph to read as follows:

7.1.3 Preparation of collection train. • • •
Assemble the train as shown in Figure 13A-1 (Method 13A) with the filter between the third and fourth impingers Alternatively, the filter may be placed between the probe the first impinger if a 20 mesh stainless steel screen is used for the filter support. • • •

• • • • •

(d) In section 7.3.4, the reference in the first paragraph to "section 7.3.6" is corrected to read "section 7.3.5".

(Secs 111, 114, and 301(a) Clean Air Act, as amended by sec. 4(a) of Pub. L. 91-604, 84 Stat. 1678 and by sec 15(c)(2) of Pub. L. 91-604, 84 Stat 1713 (42 U.S.C. 1857c-6, 1957c-9, and 1857g(2)).)

[FR Doc.76-34888 Filed 11-26-76;8:45 am]

51

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 651-5]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to Pima County Health Department On Behalf of Pima County Air Pollution Control District

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the Pima County Health Department on behalf of the Pima County Air Pollution Control District, dated October 7, 1976, EPA is today amending 40 CFR 60.4 Address, to reflect this delegation A document announcing this delegation is published today at 41 FR in the Notices section of this issue. The amended § 60.4 is set forth below. It adds the address of the Pima County Air Pollution Control District, to which must be addressed all reports, requests, applications, submittals, and communications pursuant to this part by sources subject to the NSPS located within this Air Pollution Control District.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on October 7, 1976 and it serves no purpose to delay the technical change on this addition of the Air Pollution Control District's address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended (42 U.S.C. 1867c-6).

Dated: November 19, 1976

R. L. O'CONNELL,
Acting Regional Administrator, Environmental Protection Agency, Region IX.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by adding subparagraph D to read as follows:

§ 60.4 Address.

* * * * *

(3) * * *

(A)-(C) * * *

D—Arizona

Pima County Air Pollution Control District, 151 West Congress Street, Tucson, AZ 85701

* * * * *

[FR Doc 76-35562 Filed 12-2-76,8 45 am]

52

[FRL 657-2]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State of California on Behalf of San Diego County Air Pollution Control District

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of California on behalf of the San Diego County Air Pollution Control District, dated November 8, 1976, EPA is today amending 40 CFR 60.4 Address, to reflect this delegation. A Notice announcing this delegation is published in the Notices section of this issue, under EPA (FR Doc. 76-36929 at page 54798). The amended § 60.4 is set forth below. It adds the address of the San Diego County Air Pollution Control District, to which must be addressed all reports, requests, applications, submittals, and communications pursuant to this part by sources subject to the NSPS located within this Air Pollution Control District.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected in this administrative amendment was effective on November 8, 1976 and it serves no purpose to delay the technical change on this addition of the Air Pollution Control District's address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of section 111 of the Clean Air Act, as amended (42 U.S.C. 1857c-6).

Dated: November 26, 1976.

SHELIA M. PRINDIRVILLE,
Acting Regional Administrator, Environmental Protection Agency, Region IX.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph F to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)-(E) * * *

F-California:

Bay Area Air Pollution Control District, 939 Ellis Street, San Francisco, CA 94109.

Del Norte County Air Pollution Control District, Courthouse, Crescent City, CA 95531.

Fresno County Air Pollution Control District, 515 S. Cedar Avenue, Fresno, CA 93702.

Humboldt County Air Pollution Control District, 5600 S. Broadway, Eureka, CA 95501.

Kern County Air Pollution Control District, 1700 Flower Street (P.O. Box 997), Bakersfield, CA 93302.

Madera County Air Pollution Control District, 135 W. Yosemite Avenue, Madera, CA 93637.

Mendocino County Air Pollution Control District, County Courthouse, Ukiah, CA 95482.

Monterey Bay Unified Air Pollution Control District, 420 Church Street (P.O. Box 487) Salinas, CA 93901.

Northern Sonoma County Air Pollution Control District, 3313 Chanate Road, Santa Rosa, CA 95404.

Sacramento County Air Pollution Control District, 3701 Branch Center Road, Sacramento, CA 95827.

San Diego County Air Pollution Control District, 9150 Chesapeake Drive, San Diego, CA 92123.

San Joaquin County Air Pollution Control District, 1601 E. Hazelton Street (P.O. Box 2009) Stockton, CA 95201.

Santa Barbara County Air Pollution Control District, 4440 Calle Real, Santa Barbara, CA 93110.

Stanislaus County Air Pollution Control District, 820 Scenic Drive, Modesto, CA 95350.

Trinity County Air Pollution Control District, Box AJ, Weaverville, CA 96093.

Ventura County Air Pollution Control District, 625 E. Santa Clara Street, Ventura, CA 93001.

* * * * *

[FR Doc.76 36925 Filed 12-14-76,8:45 am]

53 [FRL 661-6]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to the State of Ohio

Pursuant to the delegation of authority to implement the standards of performance for new stationary sources (NSPS) to the State of Ohio on August 4, 1976, EPA is today amending 40 CFR 60.4 Address to reflect this delegation. A Notice announcing this delegation is published in the Notices section of this issue of the FEDERAL REGISTER (FR Doc. 76-37487). The amended § 60.4 is set forth below which adds the addresses of the Agencies in Ohio which assist the State in the delegated authority to that list of addresses to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must be sent.

The Administrator finds good cause for foregoing prior notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on August 4, 1976, and it serves no purpose to delay the technical change of this addition of the addresses to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of section 111 of the Clean Air Act, as amended.

(42 U.S.C. 1857c-6)

Dated: December 10, 1976.

GEORGE R. ALEXANDER, Jr.,
Regional Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4, paragraph (b) is amended by revising subparagraph KK, to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)-(JJ) * * *

(KK) Ohio—

Medina, Summit and Portage Counties; Director, Air Pollution Control, 177 South Broadway, Akron, Ohio, 44308.

Stark County; Director, Air Pollution Control Division, Canton City Health Department, City Hall, 218 Cleveland Avenue SW, Canton, Ohio, 44702.

Butler, Clermont, Hamilton and Warren Counties; Superintendent, Division of Air Pollution Control, 2400 Beekman Street, Cincinnati, Ohio, 45214.

Cuyahoga County; Commissioner, Division of Air Pollution Control, Department of Public Health and Welfare, 2735 Broadway Avenue, Cleveland, Ohio, 44115.

Lorain County; Control Officer, Division of Air Pollution Control, 200 West Erie Avenue, 7th Floor, Lorain, Ohio, 44052.

Belmont, Carroll, Columbiana, Harrison, Jefferson, and Monroe Counties; Director, North Ohio Valley Air Authority (NOVAA), 814 Adams Street, Steubenville, Ohio, 43952.

Clark, Darke, Greene, Miami, Montgomery, and Preble Counties; Supervisor, Regional Air Pollution Control Agency (RAPCA), Montgomery County Health Department, 451 West Third Street, Dayton, Ohio, 45402

Lucas County and the City of Rossford (in Wood County); Director, Toledo Pollution Control Agency, 26 Main Street, Toledo, Ohio, 43605.

Adams, Brown, Lawrence, and Scioto Counties, Engineer-Director, Air Division, Portsmouth City Health Department, 740 Second Street, Portsmouth, Ohio, 45662

Allen, Ashland, Auglaize, Crawford, Defiance, Erie, Fulton, Hancock, Hardin, Henry, Huron Knox, Marion, Mercer, Morrow, Ottawa, Paulding, Putnam, Richland, Sandusky, Seneca, Van Wert, Williams, Wood (except City of Rossford), and Wyandot Counties, Ohio Environmental Protection Agency, Northwest District Office, 111 West Washington Street, Bowling Green, Ohio, 43402

Ashtabula, Geauga, Lake, Mahoning, Trumbull, and Wayne Counties, Ohio Environmental Protection Agency, Northeast District Office, 2110 East Aurora Road, Twinsburg, Ohio, 44087.

Athens, Coshocton Gallia, Guernsey, Highland, Hocking, Holmes, Jackson, Meigs, Morgan, Muskingum, Noble, Perry, Pike, Ross, Tuscarawas, Vinton, and Washington Counties; Ohio Environmental Protection Agency, Southeast District Office, Route 3, Box 603, Logan, Ohio, 43138.

Champaign, Clinton, Logan, and Shelby Counties; Ohio Environmental Protection Agency, Southwest District Office, 7 East Fourth Street, Dayton, Ohio, 45402.

Delaware, Fairfield, Fayette, Franklin, Licking, Madison, Pickaway, and Union Counties; Ohio Environmental Protection Agency, Central District Office, 369 East Broad Street, Columbus, Ohio, 43215.

* * * * *

[FR Doc 76-37488 Filed 12-20-76;8:45 am]

FEDERAL REGISTER, VOL. 41, NO. 246

TUESDAY, DECEMBER 21, 1976

54 (FRL 665-1)

SUBCHAPTER C—AIR PROGRAMS

DELEGATION OF AUTHORITY—NEW SOURCE REVIEW

Delegation of Authority to the State of North Carolina

The amendments below institute certain address changes for reports and applications required from operators of new sources. EPA has delegated to the State of North Carolina authority to review new and modified sources. The delegated authority includes the reviews under 40 CFR Part 52 for the prevention of significant deterioration. It also includes the reviews under 40 CFR Part 60 for the standards of performance for new stationary sources and reviews under 40 CFR Part 61 for national emission standards for hazardous air pollutants.

A notice announcing the delegation of authority is published elsewhere in this issue of the FEDERAL REGISTER. These amendments provide that all reports, requests, applications, submittals, and communications previously required for the delegated reviews will now be sent instead to the North Carolina Environmental Management Commission, Department of Natural and Economic Resources, Division of Environmental Management, P.O. Box 27687, Raleigh, North Carolina 27611. Attention: Air Quality Section, instead of EPA's Region IV.

The Regional Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on November 24, 1976, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal regulations.

This rulemaking is effective immediately, and is issued under the authority of Sections 101, 110, 111, 112, and 301 of the Clean Air Act, as amended, 42 U.S.C. 1857, 1857c-5, 6, 7 and 1857g.

Dated: December 21, 1976.

JOHN A. LITTLE,
Deputy Regional Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

2. Part 60 of Chapter I, Title 40, Code of Federal Regulations, is amended as follows: In § 60.4, paragraph (b) is amended by revising subparagraph (II) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)-(HH) * * *

(II) North Carolina Environmental Management Commission, Department of Natural and Economic Resources, Division of Environmental Management, P.O. Box 27687, Raleigh, North Carolina 27611. Attention: Air Quality Section.

* * * * *

SUBCHAPTER C—AIR PROGRAMS

[FRL 664-3]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State of Nebraska

Pursuant to the delegation of authority for the Standards of Performance for New Stationary Sources (NSPS), to the State of Nebraska on November 24, 1975, the Environmental Protection Agency (EPA) is today amending 40 CFR 60.4, [Address.], to reflect this delegation. A notice announcing this delegation is published (December 30, 1976), in the FEDERAL REGISTER. Effective immediately all requests, reports, applications, submittals, and other communications concerning the 12 source categories of the

NSPS which were promulgated December 23, 1971, and March 8, 1974, shall be sent to Nebraska Department of Environmental Control (DEC), P.O. Box 94653, State House Station, Lincoln, Nebraska 68509. However, reports required pursuant to 40 CFR 60.7(a) shall be sent to EPA, Region VII, 1735 Baltimore, Kansas City, Missouri 64108, as well as to the State.

The Regional Administrator finds good cause for forgoing prior public notice and making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. This delegation, which is reflected by this administrative amendment, was effective on November 24, 1975, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended.

(42 U.S.C. 1857c-6.)

Dated: December 20, 1976.

JEROME H. SVORE,
Regional Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (CC) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)–(BB) * * *

(CC) Nebraska Department of Environmental Control, P.O. Box 94653, State House Station, Lincoln, Nebraska 68509.

[FR Doc.76-38234 Filed 12-29-76;8:45 am]

[FRL 664-6]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to the State of Iowa

Pursuant to the delegation of authority for New Source Performance Standards (NSPS) to the State of Iowa on June 6, 1975, the Environmental Protection Agency is today amending 40 CFR 60.4, [Address.] to reflect this delegation. A notice announcing this delegation is published (December 30, 1976), in the FEDERAL REGISTER.

The amended § 60.4 provides that all reports, requests, applications, submittals, and other communications required for the 11 source categories of the NSPS, which were delegated to the State, shall be sent to the Iowa Department of Environmental Quality (DEQ), 3920 Delaware Avenue, P.O. Box 3326, Des Moines, Iowa 50316. However, reports required pursuant to 40 CFR 60.7(a) shall be sent to EPA, Region VII, 1735 Baltimore, Kansas City, Missouri 64108, as well as to the State.

The Regional Administrator finds good cause to forgo prior public notice and make this rulemaking effective immediately in that it is an administrative change and not one of substantive content. The delegation was effective June 6, 1975, and it serves no purpose to delay the technical change of the addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately and is issued under the authority of Section 111 of the Clean Air Act, as amended.

(42 U.S.C. 1857c-6.)

Dated: December 20, 1976.

JEROME H. SVORE,
Regional Administrator.

Part 60 of Chapter 1, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4, paragraph (b) is amended by revising subparagraph Q, to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)–(P) * * *

(Q) State of Iowa, Department of Environmental Quality, 3920 Delaware, P.O. Box 3326, Des Moines, Iowa 50316.

* * * * *

[FR Doc.76-38241 Filed 12-29-76;8:45 am]

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 668-1]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCE

Delegation of Authority to State of Vermont

Pursuant to the delegation of authority for the Standards of Performance for New Stationary Sources (NSPS) to the State of Vermont on September 3, 1976, FPA is today amending 40 CFR 60.4, *Address*, to reflect this delegation. A notice announcing this delegation is published today in the FEDERAL REGISTER. (See FR Doc. 77-546 appearing in the Notices section of this issue). The amended § 60.4, which adds the address of the Vermont Agency of Environmental Protection to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on September 3, 1976, and it serves no purpose to delay the technical change of this addition to the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended. 42 U.S.C. 1857c-6.

Dated: December 17, 1976.

JOHN A. S. MCGLENNON,
Regional Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (UU) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(UU)—State of Vermont, Agency of Environmental Protection, Box 489, Montpelier, Vermont 05602.

* * * * *

[FR Doc.77-547 Filed 1-5-77;8:45 am]

56 Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 673-6]

NEW SOURCE REVIEW

Delegation of Authority to the State of South Carolina

The amendments below institute certain address changes for reports and applications required from operators of new sources. EPA has delegated to the State of South Carolina authority to review new and modified sources. The delegated authority includes the reviews under 40 CFR Part 52 for the prevention of significant deterioration. It also includes the review under 40 CFR Part 60 for the standards of performance for new stationary sources and review under 40 CFR Part 61 for national emission standards for hazardous air pollutants.

A notice announcing the delegation of authority is published elsewhere in the notices section of this issue of the FEDERAL REGISTER. These amendments provide that all reports, requests, applications, submittals, and communications previously required for the delegated reviews will now be sent to the Office of Environmental Quality Control, Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201, instead of EPA's Region IV.

The Regional Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on October 19, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of sections 101, 110, 111, 112, and 301 of the Clean Air Act, as amended, 42 U.S.C. 1857c-5, 6, 7 and 1857g.

Dated: January 11, 1977.

JOHN A. LITTLE,
Acting Regional Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

DELEGATION OF AUTHORITY TO THE STATE OF SOUTH CAROLINA

2. Part 60 of Chapter I, Title 40, Code of Federal Regulations, is amended by revising subparagraph (PP) of § 60.4(b) to read as follows:

§ 60.4 *Address.*

* * * * *

(b) * * *

(A)-(OO) * * *

(PP) State of South Carolina, Office of Environmental Quality Control, Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201.

ENVIRONMENTAL PROTECTION AGENCY

[FRL 675-4]

AIR PROGRAMS—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Receipt of Application and Approval of Alternative Performance Test Method

On January 26, 1976 (41 FR 3826), the Environmental Protection Agency (EPA) promulgated standards of performance for new primary aluminum reduction plants under 40 CFR Part 60. The standards limit air emissions of gaseous and particulate fluorides from new and modified primary aluminum reduction plants. The owners or operators of affected facilities are required to determine compliance with these standards by conducting a performance test as specified in Appendix A—Reference Methods, Method 13A or 13B, "Determination of Total Fluoride Emissions from Stationary Sources" published in the FEDERAL REGISTER August 6, 1975 (40 FR 33157). As provided in 40 CFR 60.8(b), (2) and (3), the Administrator may approve the use of an equivalent test method or may approve the use of an alternative method if the method has been shown to be adequate for the determination of compliance with the standard. Method 13A specified that total fluorides be determined by the SPADNS Zirconium Lake colormetric method, and Method 13B specified that this determination be made by the specific ion electrode method.

On September 3, 1976, EPA received written application for approval of equivalency for a third analytical technique from Kaiser Aluminum and Chemical Corporation, Oakland, California. Specifically, the application requested approval of ASTM Method D 3270-73T, "Tentative Method of Analysis for Fluoride Content of the Atmosphere and Plant Tissues," 1974 Annual Book of ASTM Standards—Part 26.

Specific guidelines for the determination of method equivalency have not been established by EPA. However, EPA has completed a technical review of the application and has determined that the ASTM method will produce results adequate for the determination of compliance with the standards of performance for new primary aluminum plants. Therefore, EPA approves the ASTM method as an alternative to the analytical procedures specified in paragraph 7.3 "Analysis" of Method 13A or 13B for aluminum plants, pursuant to 40 CFR 60.8(b)(3).

Dated: January 18, 1977.

ROGER STRELOW,
Assistant Administrator for Air and Waste Management.

[FR Doc.77-2385 Filed 1-25-77;8:45 am]

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 669-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Revisions to Emission Monitoring Requirements and to Reference Methods

On October 6, 1975 (40 FR 46250), under sections 111, 114, and 301 of the Clean Air Act, as amended, the Environmental Protection Agency (EPA) promulgated emission monitoring requirements and revisions to the performance testing Reference Methods in 40 CFR Part 60. Since that time, EPA has determined that there is a need for a number of revisions to clarify the requirements. Each of the revisions being made in 40 CFR Part 60 are discussed as follows:

1. *Section 60.13.* Paragraph (c)(3) has been rewritten to clarify that not only new monitoring systems but also upgraded monitoring systems must comply with applicable performance specifications.

Paragraph (e)(1) is revised to provide that data recording is not required more frequently than once every six minutes (rather than the previously required ten seconds) for continuous monitoring systems measuring the opacity of emissions. Since reports of excess emissions are based upon review of six-minute averages, more frequent data recording is not required in order to satisfy these monitoring requirements.

2. *Section 60.45.* Paragraphs (a) through (e) have been reorganized for clarification. In addition, restrictions on use of continuous monitoring systems for measuring oxygen on a wet basis have been removed. Prior to this revision, only dry basis oxygen monitoring equipment was acceptable. Procedures for use of wet basis oxygen monitoring equipment have been approved by EPA and were published in the FEDERAL REGISTER as an alternative procedure (41 FR 44838).

Also deleted from § 60.45 are restrictions on the location of a carbon dioxide (CO_2) continuous monitoring system downstream of wet scrubber flue gas desulfurization equipment. At the time the regulations were promulgated (October 6, 1975), EPA thought that limestone scrubbers were operated under conditions that could cause significant generation or absorption of CO by the scrubbing solution which would cause errors in the monitoring results. EPA investigated this potential problem and concluded that lime or limestone scrubbers under typical conditions of operation do not significantly alter the concentration of CO in the flue gas and would not introduce significant errors into the monitoring results. Lime scrubbers operate at a pH level between 7 and 8 which will maximize SO_2 absorption and minimize CO absorption. Thus, the effect of CO_2 loss on the emission results is expected to be minimal. The exact amount of CO loss, if any, during the scrubber operation has not been determined since it is dependent upon the operating conditions for a particular facility. Although each percent of CO_2 absorption will result in a positive bias of 7.1 percent (at a stack concentration of 14 percent CO_2) in the final emission results, i.e. the indicated results may be higher than actual stack concentrations, the actual bias is expected to be very small since the amount of CO_2 absorption will be much less than one percent.

In flue gases from limestone scrubbers, there exists a possibility of the addition of CO_2 from the scrubbing reaction to the CO_2 from the fuel combustion. Every two molecules of SO_2 reacting with the limestone will produce a molecule of CO_2. Limestone scrubbers are typically operated at an approximate temperature of 50° C under acidic conditions. At these operating conditions the amount of CO_2 generated in a 90 percent efficiency scrubber is 1350 ppm or 0.135 percent CO_2. This will introduce a negative bias of 1 to 1.5 percent for a CO_2 level of 8 to 15 percent. This amount of potential error compares favorably with systems previously approved. Therefore, EPA is removing the restrictions which limited the installation of carbon dioxide continuous monitoring systems to a location upstream of the scrubber.

Several other revisions are being made to paragraphs (a), (b), (c), and (e) of Subpart D which improve the clarity or further define the intent of the regulations. Paragraph (d) has been reserved for later addition of fuel monitoring provisions.

3. *Performance Specification 1.* Paragraph 6.2 has been rewritten to clarify requirements that must be met by continuous opacity monitor manufacturers. Manufacturers must certify that at least one analyzer from each month's production was tested and meets all applicable requirements. If any requirements are not met, the production for the month must be resampled according to military standard 105D (MIL-STD-105D) and retested. Previously the regulation required that each unit of production had to be tested. Copies of MIL-STD-105D may be purchased from the Superintendent of Documents, U.S. Government Printing Office, Washington D.C. 20402.

4. *Performance Specification 2.* Figure 2-3 of Performance Specification 2 has been corrected to properly define the term "mean differences." The corrections in the operations now conform with the statistical definitions of the specifications.

5. *General.* These amendments provide optional monitoring procedures that may be selected by an owner or operator of a facility affected by the monitoring requirements of 40 CFR Part 60. Certain editorial clarifications are also included. Proposal of these amendments is not necessary because the changes are either interpretative in nature, or represent minor changes in instrumentation testing and data recording, or allow a wider selection of equipment to be used. These changes will have no effect upon the number of emission sources that must be monitored or the quality of the resultant emission data. The changes are consistent with recent determinations of the Administrator with respect to use of alternative continuous monitoring systems.

6. *Effective date.* These revisions become effective March 2, 1977.

(Secs. 111, 114, 301(a), Clean Air Act, as amended, Pub. L. 91-604, 84 Stat. 1678 (42 U.S.C. 1857c-6, 1857c-9, 1857g(a)).)

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Inflation Impact Statement under Executive Order 11821 and OMB Circular A-107.

Dated: January 19, 1977.

JOHN QUARLES,
Acting Administrator.

In 40 CFR Part 60 Subpart A, Subpart D, and Appendix B are amended as follows:

Subpart A—General Provisions

1. Section 60.13 is amended by revising paragraphs (c)(3) and (e)(1) as follows:

§ 60.13 Monitoring requirements.

* * * * *

(c) * * *

(3) All continuous monitoring systems referenced by paragraph (c)(2) of this section shall be upgraded or replaced (if necessary) with new continuous monitoring systems, and the new or improved systems shall be demonstrated to comply with applicable performance specifications under paragraph (c)(1) of this section on or before September 11, 1979.

* * * * *

(e) * * *

(1) All continuous monitoring systems referenced by paragraphs (c)(1) and (c)(2) of this section for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive ten-second period and one cycle of data recording for each successive six-minute period.

* * * * *

Subpart D—Standards of Performance for Fossil Fuel-Fired Steam Generators

2. Section 60.45 is amended by revising paragraphs (a), (b), (c), and (e) and by reserving paragraph (d) as follows:

§ 60.45 Emission and fuel monitoring.

(a) Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, and either oxygen or carbon dioxide except as provided in paragraph (b) of this section.

(b) Certain of the continuous monitoring system requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil fuel-fired steam generator that burns only gaseous fossil fuel, continuous monitoring systems for measuring the opacity of emissions and sulfur dioxide emissions are not required.

(2) For a fossil fuel-fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis under paragraph (d) of this section.

(3) Notwithstanding § 60.13(b), installation of a continuous monitoring system for nitrogen oxides may be delayed until after the initial performance tests under § 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less than 70 percent of the applicable standards in § 60.44, a continuous monitoring system for measuring nitrogen oxides emissions is not required. If the initial performance test results show that nitrogen oxide emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a continuous monitoring system for nitrogen oxides within one year after the date of the initial performance tests under § 60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator does not install any continuous monitoring systems for sulfur oxides and nitrogen oxides, as provided under paragraphs (b)(1) and (b)(3) or paragraphs (b)(2) and (b)(3) of this section a continuous monitoring system for measuring either oxygen or carbon dioxide is not required.

(c) For performance evaluations under § 60.13(c) and calibration checks under § 60.13(d), the following procedures shall be used:

(1) Reference Methods 6 or 7, as applicable, shall be used for conducting performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems.

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide	Span value for nitrogen oxides
Gas	(1)	500
Liquid	1,000	500
Solid	1,500	500
Combinations	1,000y+1,500z	500(x+y)+1,000z

[1] Not applicable.

where:

x = the fraction of total heat input derived from gaseous fossil fuel, and
y = the fraction of total heat input derived from liquid fossil fuel, and
z = the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (c)(3) of this section for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm.

(5) For a fossil fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all continuous monitoring systems shall be subject to the Administrator's approval.

(d) [Reserved]

(e) For any continuous monitoring system installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):

(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left[\frac{20.9}{20.9 - \text{percent } O_2}\right]$$

where:

E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(2) When a continuous monitoring system for measuring carbon dioxide is selected, the measurement of the pollutant concentration and carbon dioxide concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left[\frac{100}{\text{percent } CO_2}\right]$$

where:

E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

APPENDIX B—PERFORMANCE SPECIFICATIONS

3. Performance Specification 1 is amended by revising paragraph 6.2 as follows:

* * * * *

6. * * *

6.2 Conformance with the requirements of section 6.1 may be demonstrated by the owner or operator of the affected facility by testing each analyzer or by obtaining a certificate of conformance from the instrument manufacturer. The certificate must certify that at least one analyzer from each month's production was tested and satisfactorily met all applicable requirements. The certificate must state that the first analyzer randomly sampled met all requirements of paragraph 6 of this specification. If any of the requirements were not met, the certificate must show that the entire month's analyzer production was resampled according to the military standard 105D sampling procedure (MIL–STD–105D) inspection level II; was retested for each of the applicable requirements under paragraph 6 of this specification; and was determined to be acceptable under MIL–STD–105D procedures. The certificate of conformance must show the results of each test performed for the analyzers sampled during the month the analyzer being installed was produced.

* * * * *

4. Performance Specification 2 is amended by revising Figure 2–3 as follows:

Test No.	Date and Time	Reference Method Samples: SO_2 Sample 1 (ppm)	NO_x Sample 1 (ppm)	NO_x Sample 2 (ppm)	NO_x Sample 3 (ppm)	NO_x Sample Average (ppm)	Analyzer 1-Hour Average (ppm)* SO_2	Analyzer 1-Hour Average (ppm)* NO_x	Difference (ppm) SO_2	Difference (ppm) NO_x
1										
2										
3										
4										
5										
6										
7										
8										
9										

Mean reference method test value (SO_2) _____ Mean reference method test value (NO_x) _____ * Mean of the differences _____

95% Confidence intervals = ± _____ ppm (SO_2) = ± _____ ppm (NO_x)

Accuracies = $\frac{\text{Mean of the differences} + 95\% \text{ confidence interval}}{\text{Mean reference method value}} \times 100$ = ____% (SO_2) = ____% (NO_x)

* Explain and report method used to determine integrated averages

Figure 2-3. Accuracy Determination (SO_2 and NO_x)

(Secs. 111, 114, 301(a), Clean Air Act, as amended, Pub. L. 91–604, 84 Stat. 1678 (42 U.S.C. 1857c–6, 1857–9, 1857g(a))).

[FR Doc.77-2744 Filed 1-28-77;8:45 am]

NSPS which were promulgated December 23, 1971, and March 8, 1974, shall be sent to Nebraska Department of Environmental Control (DEC), P.O. Box 94653, State House Station, Lincoln, Nebraska 68509. However, reports required pursuant to 40 CFR 60.7(a) shall be sent to EPA, Region VII, 1735 Baltimore, Kansas City, Missouri 64108, as well as to the State.

The Regional Administrator finds good cause for forgoing prior public notice and making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. This delegation, which is reflected by this administrative amendment, was effective on November 24, 1975, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended.

(42 U.S.C. 1857c-6.)

Dated: December 20, 1976.

JEROME H. SVORE,
Regional Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (CC) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)–(BB) * * *

(CC) Nebraska Department of Environmental Control, P.O. Box 94653, State House Station, Lincoln, Nebraska 68509.

[FR Doc.76-38234 Filed 12-29-76,8:45 am]

[FRL 664-6]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to the State of Iowa

Pursuant to the delegation of authority for New Source Performance Standards (NSPS) to the State of Iowa on June 6, 1975, the Environmental Protection Agency is today amending 40 CFR 60.4, [Address.] to reflect this delegation. A notice announcing this delegation is published (December 30, 1976), in the FEDERAL REGISTER.

The amended § 60.4 provides that all reports, requests, applications, submittals, and other communications required for the 11 source categories of the NSPS, which were delegated to the State, shall be sent to the Iowa Department of Environmental Quality (DEQ), 3920 Delaware Avenue, P O. Box 3326, Des Moines, Iowa 50316. However, reports required pursuant to 40 CFR 60.7(a) shall be sent to EPA, Region VII, 1735 Baltimore, Kansas City, Missouri 64108, as well as to the State.

The Regional Administrator finds good cause to forgo prior public notice and make this rulemaking effective immediately in that it is an administrative change and not one of substantive content. The delegation was effective June 6, 1975, and it serves no purpose to delay the technical change of the addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately and is issued under the authority of Section 111 of the Clean Air Act, as amended.

(42 U.S.C. 1857c-6.)

Dated: December 20, 1976.

JEROME H. SVORE,
Regional Administrator.

Part 60 of Chapter 1, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4, paragraph (b) is amended by revising subparagraph Q, to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)–(P) * * *

(Q) State of Iowa, Department of Environmental Quality, 3920 Delaware, P.O. Box 3326, Des Moines, Iowa 50316.

* * * * *

[FR Doc.76-38241 Filed 12-29-76;8:45 am]

55 Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 668-1]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCE

Delegation of Authority to State of Vermont

Pursuant to the delegation of authority for the Standards of Performance for New Stationary Sources (NSPS) to the State of Vermont on September 3, 1976, EPA is today amending 40 CFR 60.4, *Address*, to reflect this delegation. A notice announcing this delegation is published today in the FEDERAL REGISTER. (See FR Doc. 77-546 appearing in the Notices section of this issue). The amended § 60.4, which adds the address of the Vermont Agency of Environmental Protection to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on September 3, 1976, and it serves no purpose to delay the technical change of this addition to the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended. 42 U.S.C. 1857c-6.

Dated: December 17, 1976.

JOHN A. S. MCGLENNON,
Regional Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (UU) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(UU)—State of Vermont, Agency of Environmental Protection, Box 489, Montpelier, Vermont 05602.

* * * * *

[FR Doc.77-547 Filed 1-5-77;8:45 am]

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 673-6]

NEW SOURCE REVIEW

Delegation of Authority to the State of South Carolina

The amendments below institute certain address changes for reports and applications required from operators of new sources. EPA has delegated to the State of South Carolina authority to review new and modified sources. The delegated authority includes the reviews under 40 CFR Part 52 for the prevention of significant deterioration. It also includes the review under 40 CFR Part 60 for the standards of performance for new stationary sources and review under 40 CFR Part 61 for national emission standards for hazardous air pollutants.

A notice announcing the delegation of authority is published elsewhere in the notices section of this issue of the FEDERAL REGISTER. These amendments provide that all reports, requests, applications, submittals, and communications previously required for the delegated reviews will now be sent to the Office of Environmental Quality Control, Departpartment of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201, instead of EPA's Region IV.

The Regional Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on October 19, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of sections 101, 110, 111, 112, and 301 of the Clean Air Act, as amended, 42 U.S.C. 1857c-5, 6, 7 and 1857g.

Dated: January 11, 1977.

JOHN A. LITTLE,
Acting Regional Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

DELEGATION OF AUTHORITY TO THE STATE OF SOUTH CAROLINA

2. Part 60 of Chapter I, Title 40, Code of Federal Regulations, is amended by revising subparagraph (PP) of § 60.4(b) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)-(OO) * * *

(PP) State of South Carolina, Office of Environmental Quality Control, Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201.

ENVIRONMENTAL PROTECTION AGENCY

[FRL 675-4]

AIR PROGRAMS—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Receipt of Application and Approval of Alternative Performance Test Method

On January 26, 1976 (41 FR 3826), the Environmental Protection Agency (EPA) promulgated standards of performance for new primary aluminum reduction plants under 40 CFR Part 60. The standards limit air emissions of gaseous and particulate fluorides from new and modified primary aluminum reduction plants. The owners or operators of affected facilities are required to determine compliance with these standards by conducting a performance test as specified in Appendix A—Reference Methods, Method 13A or 13B, "Determination of Total Fluoride Emissions from Stationary Sources" published in the FEDERAL REGISTER August 6, 1975 (40 FR 33157). As provided in 40 CFR 60.8(b), (2) and (3), the Administrator may approve the use of an equivalent test method or may approve the use of an alternative method if the method has been shown to be adequate for the determination of compliance with the standard. Method 13A specified that total fluorides be determined by the SPADNS Zirconium Lake colormetric method, and Method 13B specified that this determination be made by the specific ion electrode method.

On September 3, 1976, EPA received written application for approval of equivalency for a third analytical technique from Kaiser Aluminum and Chemical Corporation, Oakland, California. Specifically, the application requested approval of ASTM Method D 3270-73T, "Tentative Method of Analysis for Fluoride Content of the Atmosphere and Plant Tissues," 1974 Annual Book of ASTM Standards—Part 26.

Specific guidelines for the determination of method equivalency have not been established by EPA. However, EPA has completed a technical review of the application and has determined that the ASTM method will produce results adequate for the determination of compliance with the standards of performance for new primary aluminum plants. Therefore, EPA approves the ASTM method as an alternative to the analytical procedures specified in paragraph 7.3 "Analysis" of Method 13A or 13B for aluminum plants, pursuant to 40 CFR 60.8(b)(3).

Dated: January 18, 1977.

ROGER STRELOW,
Assistant Administrator for Air and Waste Management.

[FR Doc.77-2385 Filed 1-25-77;8:45 am]

...re it is dependent upon the ...ditions, for a particular la... ...ich percent of CO: ab... ...in a positive bias of ...ncentration of ...l emission ...may be ...ions,

...emission d... ...ent with ... Administrator with... ...ternative continuous mo...

6 *Effective date.* These ...come effective March 2, 1977.

(Secs. 111, 114, 301(a), Clean Air Act, as amended, Pub. L. 91-604, 84 Stat. 1678 (42 U.S.C. 1857c-6, 1857c-9, 1857g(a)).)

NOTE.—The Environmental Protection ...has determined that this document ...contain a major proposal requiring ...of an Inflation Impact State... ...tive Order 11821 and OMB

...LES,

...for.

...el-fired steam gen-
...not use a flue gas de-
...device, a continuous moni-
...system for measuring sulfu
...emissions is not required
...owner or operator monitor
...oxide emissions by fue
...analysis under par
...section.

(3) Not
...stallat
...sys

(4

57

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 669-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Revisions to Emission Monitoring Requirements and to Reference Methods

On October 6, 1975 (40 FR 46250), under sections 111, 114, and 301 of the Clean Air Act, as amended, the Environmental Protection Agency (EPA) promulgated emission monitoring requirements and revisions to the performance testing Reference Methods in 40 CFR Part 60. Since that time, EPA has determined that there is a need for a number of revisions to clarify the requirements. Each of the revisions being made in 40 CFR Part 60 are discussed as follows:

1. *Section 60.13.* Paragraph (c)(3) has been rewritten to clarify that not only new monitoring systems but also upgraded monitoring systems must comply with applicable performance specifications.

Paragraph (e)(1) is revised to provide that data recording is not required more frequently than once every six minutes (rather than the previously required ten seconds) for continuous monitoring systems measuring the opacity of emissions. Since reports of excess emissions are based upon review of six-minute averages, more frequent data recording is not required in order to satisfy these monitoring requirements

2. *Section 60.45.* Paragraphs (a) through (e) have been reorganized for clarification. In addition, restrictions on use of continuous monitoring systems for measuring oxygen on a wet basis have been removed. Prior to this revision, only dry basis oxygen monitoring equipment was acceptable. Procedures for use of wet basis oxygen monitoring equipment have been approved by EPA and were published in the FEDERAL REGISTER as an alternative procedure (41 FR 44838).

Also deleted from § 60.45 are restrictions on the location of a carbon dioxide (CO_2) continuous monitoring system downstream of wet scrubber flue gas desulfurization equipment At the time the regulations were promulgated (October 6, 1975), EPA thought that limestone scrubbers were operated under conditions that could cause significant generation or absorption of CO by the scrubbing solution which would cause errors in the monitoring results EPA investigated this potential problem and concluded that lime or limestone scrubbers under typical conditions of operation do not significantly alter the concentration of CO_2 in the flue gas and would not introduce significant errors into the monitoring results. Lime scrubbers operate at a pH level between 7 and 8 which will maximize SO_2 absorption and minimize CO absorption. Thus, the effect of CO_2 loss on the emission results is expected to be minimal The exact amount of CO loss, if any, during the scrubber operation has not been determined since it is dependent upon the operating conditions for a particular facility Although each percent of CO_2 absorption will result in a positive bias of 7.1 percent (at a stack concentration of 14 percent CO_2) in the final emission results, i.e. the indicated results may be higher than actual stack concentrations, the actual bias is expected to be very small since the amount of CO_2 absorption will be much less than one percent.

In flue gases from limestone scrubbers, there exists a possibility of the addition of CO_2 from the scrubbing reaction to the CO_2 from the fuel combustion. Every two molecules of SO_2 reacting with the limestone will produce a molecule of CO_2. Limestone scrubbers are typically operated at an approximate temperature of 50° C under acidic conditions. At these operating conditions the amount of CO_2 generated in a 90 percent efficiency scrubber is 1350 ppm or 0.135 percent CO_2. This will introduce a negative bias of 1 to 1.5 percent for a CO_2 level of 8 to 15 percent. This amount of potential error compares favorably with systems previously approved Therefore, EPA is removing the restrictions which limited the installation of carbon dioxide continuous monitoring systems to a location upstream of the scrubber.

Several other revisions are being made to paragraphs (a), (b), (c), and (e) of Subpart D which improve the clarity or further define the intent of the regulations. Paragraph (d) has been reserved for later addition of fuel monitoring provisions.

3. *Performance Specification 1.* Paragraph 6.2 has been rewritten to clarify requirements that must be met by continuous opacity monitor manufacturers. Manufacturers must certify that at least one analyzer from each month's production was tested and meets all applicable requirements. If any requirements are not met, the production for the month must be resampled according to military standard 105D (MIL-STD-105D) and retested Previously the regulation required that each unit of production had to be tested Copies of MIL-STD-105D may be purchased from the Superintendent of Documents, U.S. Government Printing Office, Washington D.C. 20402.

4. *Performance Specification 2.* Figure 2-3 of Performance Specification 2 has been corrected to properly define the term "mean differences." The corrections in the operations now conform with the statistical definitions of the specifications.

5 *General.* These amendments provide optional monitoring procedures that may be selected by an owner or operator of a facility affected by the monitoring requirements of 40 CFR Part 60 Certain editorial clarifications are also included. Proposal of these amendments is not necessary because the changes are either interpretative in nature, or represent minor changes in instrumentation testing and data recording, or allow a wider selection of equipment to be used These changes will have no effect upon the number of emission sources that must be monitored or the quality of the resultant emission data. The changes are consistent with recent determinations of the Administrator with respect to use of alternative continuous monitoring systems.

6. *Effective date.* These revisions become effective March 2, 1977.

(Secs 111, 114, 301(a), Clean Air Act, as amended, Pub L. 91-604, 84 Stat. 1678 (42 U.S.C. 1857c-6, 1857c-9, 1857g(a)).)

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Inflation Impact Statement under Executive Order 11821 and OMB Circular A-107

Dated: January 19, 1977.

JOHN QUARLES,
Acting Administrator.

In 40 CFR Part 60 Subpart A, Subpart D, and Appendix B are amended as follows:

Subpart A—General Provisions

1. Section 60.13 is amended by revising paragraphs (c)(3) and (e)(1) as follows:

§ 60.13 Monitoring requirements.

* * * * *

(c) * * *

(3) All continuous monitoring systems referenced by paragraph (c)(2) of this section shall be upgraded or replaced (if necessary) with new continuous monitoring systems, and the new or improved systems shall be demonstrated to comply with applicable performance specifications under paragraph (c)(1) of this section on or before September 11, 1979.

* * * * *

(e) * * *

(1) All continuous monitoring systems referenced by paragraphs (c)(1) and (c)(2) of this section for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive ten-second period and one cycle of data recording for each successive six-minute period.

* * * * *

Subpart D—Standards of Performance for Fossil Fuel-Fired Steam Generators

2. Section 60.45 is amended by revising paragraphs (a), (b), (c), and (e) and by reserving paragraph (d) as follows:

§ 60.45 Emission and fuel monitoring.

(a) Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, and either oxygen or carbon dioxide except as provided in paragraph (b) of this section.

(b) Certain of the continuous monitoring system requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil fuel-fired steam generator that burns only gaseous fossil fuel, continuous monitoring systems for measuring the opacity of emissions and sulfur dioxide emissions are not required.

(2) For a fossil fuel-fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis under paragraph (d) of this section.

(3) Notwithstanding § 60.13(b), installation of a continuous monitoring system for nitrogen oxides may be delayed until after the initial performance tests under § 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less than 70 percent of the applicable standards in § 60.44, a continuous monitoring system for measuring nitrogen oxides emissions is not required. If the initial performance test results show that nitrogen oxide emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a continuous monitoring system for nitrogen oxides within one year after the date of the initial performance tests under § 60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator does not install any continuous monitoring systems for sulfur oxides and nitrogen oxides, as provided under paragraphs (b)(1) and (b)(3) or paragraphs (b)(2) and (b)(3) of this section a continuous monitoring system for measuring either oxygen or carbon dioxide is not required.

(c) For performance evaluations under § 60.13(c) and calibration checks under § 60.13(d), the following procedures shall be used:

(1) Reference Methods 6 or 7, as applicable, shall be used for conducting performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems.

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide	Span value for nitrogen oxides
Gas	(1)	500
Liquid	1,000	500
Solid	1,500	500
Combinations	1,000y+1,500z	500(x+y)+1,000z

(1) Not applicable.

where:

x = the fraction of total heat input derived from gaseous fossil fuel, and
y = the fraction of total heat input derived from liquid fossil fuel, and
z = the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (c)(3) of this section for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm.

(5) For a fossil fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all continuous monitoring systems shall be subject to the Administrator's approval.

(d) [Reserved]

(e) For any continuous monitoring system installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):

(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left[\frac{20.9}{20.9 - \text{percent } O_2}\right]$$

where:

E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(2) When a continuous monitoring system for measuring carbon dioxide is selected, the measurement of the pollutant concentration and carbon dioxide concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left[\frac{100}{\text{percent } CO_2}\right]$$

where:

E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

APPENDIX B—PERFORMANCE SPECIFICATIONS

3. Performance Specification 1 is amended by revising paragraph 6.2 as follows:

* * * * *

6. * * *

6.2 Conformance with the requirements of section 6.1 may be demonstrated by the owner or operator of the affected facility by testing each analyzer or by obtaining a certificate of conformance from the instrument manufacturer. The certificate must certify that at least one analyzer from each month's production was tested and satisfactorily met all applicable requirements. The certificate must state that the first analyzer randomly sampled met all requirements of paragraph 6 of this specification. If any of the requirements were not met, the certificate must show that the entire month's analyzer production was resampled according to the military standard 105D sampling procedure (MIL-STD-105D) inspection level II; was retested for each of the applicable requirements under paragraph 6 of this specification; and was determined to be acceptable under MIL-STD-105D procedures. The certificate of conformance must show the results of each test performed for the analyzers sampled during the month the analyzer being installed was produced.

* * * * *

4. Performance Specification 2 is amended by revising Figure 2-3 as follows:

Test No.	Date and Time	Reference Method Samples: SO_2 Sample 1 (ppm)	NO_x Sample 1 (ppm)	NO_x Sample 2 (ppm)	NO_x Sample 3 (ppm)	NO_x Sample Average (ppm)	Analyzer 1-Hour Average (ppm)* SO_2	Analyzer 1-Hour Average (ppm)* NO_x	Difference (ppm) SO_2	Difference (ppm) NO_x
1										
2										
3										
4										
5										
6										
7										
8										
9										

Mean reference method test value (SO_2) _____ Mean reference method test value (NO_x) _____ Mean of the differences* _____

95% Confidence intervals = ± _____ ppm (SO_2) = ± _____ ppm (NO_x)

Accuracies = (Mean of the differences + 95% confidence interval) / Mean reference method value × 100 = ____% (SO_2) = ____% (NO_x)

* Explain and report method used to determine integrated averages

Figure 2-3. Accuracy Determination (SO_2 and NO_x)

(Secs. 111, 114, 301(a), Clean Air Act, as amended, Pub. L. 91-604, 84 Stat. 1678 (42 U.S.C. 1857c-6, 1857-9, 1857g(a))).

[FR Doc.77-2744 Filed 1-28-77;8:45 am]

58

[FRL 682-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to City of Philadelphia

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the City of Philadelphia on September 30, 1976, EPA is today amending 40 CFR 60.4, Address, to reflect this delegation. For a notice announcing this delegation, see FR Doc 77-3712 published in the Notices section of today's FEDERAL REGISTER. The amended § 60.4, which adds the address of the Philadelphia Department of Public Health, Air Management Services, to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this Administrative amendment was effective on September 30, 1976, and it serves no purpose to delay the technical change of this address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of section 111 of the Clean Air Act, as amended, 42 U.S.C. 1857c-6.

Dated: January 25, 1977.

A. R. MORRIS,
Acting Regional Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4, paragraph (b) is amended by revising subparagraph (NN) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)-(MM) * * *

(NN) (a) City of Philadelphia: Philadelphia Department of Public Health, Air Management Services, 801 Arch Street, Philadelphia, Pennsylvania 19107.

* * * * *

[FR Doc.77-3709 Filed 2-3-77;8:45 am]

59

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Region V Address; Correction

Section 60.4 paragraph (a) is corrected by changing Region V (Illinois, Indiana, Minnesota, Michigan, Ohio, Wisconsin), 1 North Wacker Drive, Chicago, Illinois 60606 to Region V (Illinois, Indiana, Minnesota, Michigan, Ohio, Wisconsin), 230 South Dearborn Street, Chicago, Illinois 60604.

Dated: March 21, 1977.

GEORGE R. ALEXANDER, Jr.,
Regional Administrator.

[FR Doc.77-9406 Filed 3-29-77;8:45 am]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to the State of Wisconsin

Pursuant to the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of Wisconsin on September 28, 1976, EPA is today amending 40 CFR 60.4, Address, to reflect this delegation. A Notice announcing this delegation is published today, March 30, 1977, at 42 FR 16845 in this FEDERAL REGISTER. The amended § 60.4, which adds the address of the Wisconsin Department of Natural Resources to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on September 28, 1976 and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of section 111 of the Clean Air Act, as amended. 42 U.S.C. 1857c-6.

Dated: March 21, 1977.

GEORGE R. ALEXANDER, Jr.,
Regional Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (YY), to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)-(XX) * * *

(YY) Wisconsin—

Wisconsin Department of Natural Resources, P.O. Box 7921, Madison, Wisconsin 53707.

[FR Doc.77-9404 Filed 3-29-77;8:45 am]

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 715-8]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Compliance With Standards and Maintenance Requirements

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This action amends the general provisions of the standards of performance to allow methods other than Reference Method 9 to be used as a means of measuring plume opacity. The Environmental Protection Agency (EPA) is investigating a remote sensing laser radar system of measuring plume opacity and believes it could be considered as an alternative method to Reference Method 9. This amendment would allow EPA to propose such systems as alternative methods in the future.

EFFECTIVE DATE: June 22, 1977.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone no. 919-688-8146, ext. 271.

SUPPLEMENTARY INFORMATION: As originally expressed, 40 CFR 60.11(b) permitted the use of Reference Method 9 exclusively for determining whether a source complied with an applicable opacity standard. By this action, EPA amends § 60.11(b) so that alternative methods approved by the Administrator may be used to determine opacity.

When § 60.11(b) was originally promulgated, the visible emissions (Method 9) technique of determining plume opacity with trained visible emission observers was the only expedient and accurate method available to enforcement personnel. Recently, EPA funded the development of a remote sensing laser radar system (LIDAR) that appears to produce results adequate for determination of compliance with opacity standards. EPA is currently evaluating the equipment and is considering proposing its use as an alternative technique of measuring plume opacity.

This amendment will allow EPA to consider use of the LIDAR method of determining plume opacity and, if appropriate, to approve this method for enforcement of opacity regulations. If this method appears to be a suitable alternative to Method 9, it will be proposed in the FEDERAL REGISTER for public comment. After considering comments, EPA will determine if the new method will be an acceptable means of determinig opacity compliance.

(Secs. 111, 114, 301(a), Clean Air Act, sec. 4(a) of Pub. L. 91-604, 84 Stat. 1683; sec. 4(a) of Pub. L. 91-604, 84 Stat. 1687; sec. 2 of Pub. L. No. 90-148, 81 Stat. 504 (42 U.S.C. 1857c-6, 1857c-9 and 1857g(a)).)

NOTE.—Economic Impact Analysis: The Environmental Protection Agency has determined that this action does not contain a major proposal requiring preparation of an Economic Impact Analysis under Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: May 10, 1977.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. Section 60.11 is amended by revising paragraph (b) as follows:

§ 60.11 Compliance with standards and maintenance requirements.

* * * * *

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Reference Method 9 in Appendix A of this part or any alternative method that is approved by the Administrator. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in Appendix B of this part, has been properly maintained and (at the time of the alleged violation) calibrated, and that the resulting data have not been tampered with in any way.

* * * * *

(Secs. 111, 114, 301(a), Clean Air Act, Sec. 4 (a) of Pub. L. 91-604, 84 Stat. 1683; sec. 4(a) of Pub. L. 91-604, 84 Stat. 1687; sec. 2 of Pub. L. No. 90-148 81 Stat. 504 (42 U.S.C. 1857c-6, 1857c-9, 1857g(a)).)

[FR Doc.77-14562 Filed 5-20-77;8:45 am]

Title 40—Protection of Environment

CHAPTER 1—ENVIRONMENTAL PROTECTION AGENCY

[FRL 742-5]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Petroleum Refinery Fluid Catalytic Cracking Unit Catalyst Regenerators

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This rule revises the standard which limits the opacity of omissions from new, modified, or reconstructed petroleum refinery fluid catalytic cracking unit catalyst regenerators to 30 percent, except for one six-minute period in any one hour. The revision is being made to make the standard consistent with a revision to the test method for opacity. The standard implements the Clean Air Act and is intended to require the proper operation and maintenance of fluid catalytic cracking unit catalyst regenerators.

EFFECTIVE DATE: June 24, 1976.

ADDRESSES: Copies of the comment letters and a report which contains a summary of the issues and EPA's responses are available for public inspection and copying at the U.S. Environmental Protection Agency, Public Information Reference Unit (EPA Library), Room 2922, 401 M Street SW., Washington, D.C. Copies of the report also may be obtained upon written request from the EPA Public Information Center (PM-215), Washington, D.C. 20460 (specify Comment Summary—Petroleum Refinery Fluid Catalytic Cracking Units).

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number 919-688-8146, extension 271.

SUPPLEMENTARY INFORMATION:

BACKGROUND

On June 29, 1973, the U.S. Court of Appeals for the District of Columbia Circuit remanded to EPA the standards of performance for Portland cement plants (*Portland Cement Association* v. *Ruckelshaus*, 486 F. 2d 375). One of the issues remanded was the use of opacity standards. On November 12, 1974, EPA responded to the remand (39 FR 39872) and on May 22, 1975, the Court affirmed the use of opacity standards (513 F. 2d 506).

In the remand response, EPA reconsidered the use of opacity standards and concluded that they are a reliable, inexpensive, and useful means of ensuring that control equipment is properly maintained and operated at all times. EPA also made revisions to the general pro-

visions of 40 CFR Part 60 and to the Reference Method 9.

EPA reevaluated the opacity standard for petroleum refinery fluid catalytic cracking unit catalyst regenerators in light of the revisions to Reference Method 9, and proposed a revision to this standard on August 30, 1976 (41 FR 36600). The revision is not the result of a reevaluation of the technical, economic and environmental basis for the standard. Consequently, the revised opacity standard will be neither more nor less stringent than the previous standard, and will be consistent with the mass emission standard (1.0 kg/1000 kg of coke burnoff).

Summary of Comments and EPA's Responses

EPA received six letters commenting on the proposed revision (three from industry and three from State and local governments). Two commenters pointed out that the basis for the original opacity standard assumed new fluid catalytic cracking units would be of 65,000 barrels per day capacity, but the proposed revision assumed new fluid catalytic cracking units would be of less than 50,000 barrels per day capacity. Two other commenters pointed out that the original standard allowed one three-minute exception from the opacity standard of performance to accommodate soot-blowing in the carbon monoxide boiler and that the proposed change to six-minute averages did not justify adding an additional exception.

A review of the basis for the original opacity standard indicates the commenters are correct. Large, new or modified fluid catalytic cracking units will more likely be in the range of 65,000 barrels per day capacity, and one exception per hour more accurately reflects the one three-minute exception allowed under the previous test method. The effect of increased capacity on the opacity of particulate mass emissions was discussed both in the Federal Register notice proposing revision of the opacity standard and in the background information document supporting the revision. Considering the effect on opacity of the greater capacity of a 65,000-barrel-per-day fluid catalytic cracking unit compared to a 50,000-barrel-per-day unit leads to the conclusion that the opacity standard should not be revised to 25 percent, but should remain at 30 percent opacity. Accordingly, the revised opacity standard is promulgated as 30 percent opacity with one six-minute exception period per hour.

One comment concerned § 60.11(e) of the General Provisions and questioned whether in its present form it adequately accounts for the problems of petroleum refinery fluid catalytic cracking units. Section 60.11(e) provides relief for those individual sources where, because of operating variables, opacity readings are abnormally high and cause it to exceed the standard, even though it is in compliance with the mass emission standard. The mechanism for relief is that opacity readings may be taken during initial start-up mass emission testing and a special opacity standard assigned to the source.

Petroleum refinery fluid catalytic cracking units operate continuously for periods of two years or more; and over such long periods, mass and opacity emissions gradually increase. For this reason, the mass and opacity standards were set on the basis of levels achievable at the end of the run. It is to be expected, therefore, that at the beginning of the run, both mass and opacity emissions from such units will be well below the standard, even in some cases where opacity readings are abnormally high given the mass emissions. In such cases, an individualized opacity standard based on beginning-of-run readings would not necessarily prevent the facility which still meets the mass emissions standard at the end of the run from failing an end-of-run opacity test. To alleviate this problem, EPA is adding a new § 60.106 (e) to the petroleum refinery standard which, in conjunction with §§ 60.11 (e) (2), (e) (3), and (e) (4) of the General Provisions, will permit determination of an individualized opacity standard for a fluid catalytic cracking unit during any performance test and not just the initial performance test. This will ensure that a properly operated and maintained source will not be found in violation of the opacity standard, while in compliance with the applicable mass emission standard.

The proposed amendment to § 60.102 (a) (2) specified that opacity readings of portions of plumes which contain condensed, uncombined water vapor are not to be used for determining compliance with opacity standards. Since this provision has been added to § 60.11(b) of the General Provisions, it is not necessary to repeat it in Subpart J for petroleum refineries.

Miscellaneous

The opacity standard, as modified, applies to all affected facilities for which construction or modification was commenced after June 11, 1973, the date the standard was proposed.

This revision is promulgated under the authority of sections 111, 114, and 301(a) of the Clean Air Act, as amended by Public Law 91-604, 84 Statute 1683, 1687 (42 U.S.C. 1857c-6, 1857c-9) and Public Law 90-148, 81 Statute 504 (42 U.S.C. 1857g(a)).

Note.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Statement under Executive Orders 11821 and 11949, and OMB Circular A-107.

Dated: June 24, 1977.[65]

Douglas M. Costle,
Administrator.

Part 60, Chapter I of Title 40 of the Code of Federal Regulations is amended as follows:

1. Section 60.102(a)(2) is revised to read as follows:

§ 60.102 Standard for particulate matter.

(a) * * *

(2) Gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one hour.

* * * * *

(Sec. 111, Pub. L. 91-604, 84 Stat. 1683 (42 U.S.C. 1857c-6); sec. 301(a), Pub. L. 90-148, 81 Stat. 504 (42 U.S.C. 1857g(a)).)

2. Section 60.105(e)(1) is revised to read as follows:

§ 60.105 *Emission monitoring.*

* * * * *

(e) * * *

(1) Opacity. All hourly periods which contain two or more six-minute periods during which the average opacity as measured by the continuous monitoring system exceeds 30 percent.

* * * * *

3. Section 60.106(e) is added to read as follows:

§ 60.106 Test methods and procedures.

* * * * *

(e) An owner or operator of an affected facility may request the Administrator to determine opacity of emissions from the affected facility during any performance test covered under § 60.8. In such event the provisions of §§ 60.11 (e) (2), (e) (3), and (e) (4) shall apply.

(Sec. 111, 114, Pub. L. 91-604, 84 Stat. 1683, 1687 (42 U.S.C. 1857c-6, 1857c-9); sec. 301(a), Pub. L. 90-148, 81 Stat. 504 (42 U.S.C. 1857g (a)).)

[FR Doc.77-18129 Filed 6-23-77;8:45 am]

[FRL 752-2]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Units and Abbreviations

AGENCY: Environmental Protection Agency

ACTION: Final rule

SUMMARY: This action revises the General Provisions by reorganizing the units and abbreviations and adding the International System of Units (SI). Until recently, EPA did not have a preferred system of measurement to be used in its regulations. Now the Agency is using SI units in all regulations issued under this part. This necessitates that SI units be added to the General Provisions to provide a complete listing of abbreviations used..

EFFECTIVE DATE: August 18, 1977.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone no. 919-541-5271.

SUPPLEMENTARY INFORMATION:

BACKGROUND

Section 3 of Pub. L. 94-168, the Metric Conversion Act of 1975, declares that the policy of the United States shall be to coordinate and plan the increasing use of the metric system in the United States. On December 10, 1976, a notice was published in the FEDERAL REGISTER (41 FR 54018) that set forth the interpretation and modification of the International System of Units (SI) for the United States. EPA incorporates SI units in all regulations issued under 40 CFR Part 60 and provides common equivalents in parentheses where desirable. Use of SI units requires this revision of the abbreviations section (§ 60.3) of the General Provisions of 40 CFR Part 60.

REFERENCE DOCUMENTS

An explanation of the International Systems of Units was presented in the FEDERAL REGISTER notice mentioned above (41 FR 54018). The Environmental Protection Agency is using the Standard for Metric Practice (E 380-76) published by the American Society for Testing and Materials (A.S.T.M.) as its basic reference. This document may be obtained by sending $4.00 to A.S.T.M., 1916 Race Street, Philadelphia, Pennsylvania 19103.

MISCELLANEOUS

As this revision has no regulatory impact, but only defines units and abbreviations used in this part, opportunity for public participation was judged unnecessary.

(Sections 111 and 301(a) of the Clean Air Act; sec. 4(a) of Pub. L. 91-604, 84 Stat. 1683; sec. 2 of Pub. L. 90-148, 81 Stat. 504 (42 U.S.C. 1857c-6, 1857g(a)).)

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Analysis under Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: July 8, 1977.

DOUGLAS M. COSTLE,
Administrator.

40 CFR Part 60 is amended by revising § 60.3 to read as follows:

§ 60.3 Units and abbreviations.

Used in this part are abbreviations and symbols of units of measure. These are defined as follows:

(a) System International (SI) units of measure:

A—ampere
g—gram
Hz—hertz
J—joule
K—degree Kelvin
kg—kilogram
m—meter
m^3—cubic meter
mg—milligram—10^{-3} gram
mm—millimeter—10^{-3} meter
Mg—megagram—10^6 gram
mol—mole
N—newton
ng—nanogram—10^{-9} gram
nm—nanometer—10^{-9} meter
Pa—pascal
s—second
V—volt
W—watt
Ω—ohm
μg—microgram—10^{-6} gram

(b) Other units of measure:

Btu—British thermal unit
°C—degree Celsius (centigrade)
cal—calorie
cfm—cubic feet per minute
cu ft—cubic feet
dcf—dry cubic feet
dcm—dry cubic meter
dscf—dry cubic feet at standard conditions
dscm—dry cubic meter at standard conditions
eq—equivalent
°F—degree Fahrenheit
ft—feet
gal—gallon
gr—grain
g-eq—gram equivalent
hr—hour
in—inch
k—1,000
l—liter
lpm—liter per minute
lb—pound
meq—milliequivalent
min—minute
ml—milliliter
mol. wt.—molecular weight
ppb—parts per billion
ppm—parts per million
psia—pounds per square inch absolute
psig—pounds per square inch gage
°R—degree Rankine
scf—cubic feet at standard conditions
scfh—cubic feet per hour at standard conditions
scm—cubic meter at standard conditions
sec—second
sq ft—square feet
std—at standard conditions

(c) Chemical nomenclature:

CdS—cadmium sulfide
CO—carbon monoxide
CO_2—carbon dioxide
HCl—hydrochloric acid
Hg—mercury
H_2O—water
H_2S—hydrogen sulfide
H_2SO_4—sulfuric acid
N_2—nitrogen
NO—nitric oxide
NO_2—nitrogen dioxide
NO_x—nitrogen oxides
O_2—oxygen
SO_2—sulfur dioxide
SO_3—sulfur trioxide
SO_x—sulfur oxides

(d) Miscellaneous:

A.S.T.M.—American Society for Testing and Materials

(Sections 111 and 301(a) of the Clean Air Act; sec. 4(a) of Pub. L. 91-604, 84 Stat. 1683; sec. 2 of Pub. L. 90-148, 81 Stat. 504 (42 U.S.C. 1857c-6, 1857g(a)).)

[FR Doc.77-20557 Filed 7-18-77;8:45 am]

63

[FRL 762-2]

PART 60—STANDARDS OF PERFORM ANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to the State of New Jersey

AGENCY: Environmental Protection Agency.

ACTION: Final Rule.

SUMMARY: A notice announcing EPA's delegation of authority for the New Source Performance Standards to the State of New Jersey is published at page 37387 of today's FEDERAL REGISTER. In order to reflect this delegation, this document amends EPA regulations to require the submission of all notices, reports, and other communications called for by the delegated regulations to the State of New Jersey rather than to EPA.

EFFECTIVE DATE: July 21, 1977.

FOR FURTHER INFORMATION CONTACT:

J. Kevin Healy, Attorney, U.S. Environmental Protection Agency, Region II, General Enforcement Branch, Enforcement Division, 26 Federal Plaza, New York, New York 10007, 212-264-1196).

SUPPLEMENTARY INFORMATION: On May 9, 1977 EPA delegated authority to the State of New Jersey to implement and enforce the New Source Performance Standards. A full account of the background to this action and of the exact terms of the delegation appear in the Notice of Delegation which is also published in today's FEDERAL REGISTER.

This rulemaking is effective immediately, since the Administrator has found good cause to forego prior public notice. This addition of the State of New Jersey address to the Code of Federal Regulations is a technical change and imposes no additional substantive burden on the parties affected.

Dated: July 18, 1977.

BARBARA BLUM,
Acting Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended under authority of Section 111 of the Clean Air Act (42 U.S.C. 1857c-6), as follows:

(1) In § 60.4 paragraph (b) is amended by revising subparagraph (FF) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(FF)—State of New Jersey: New Jersey Department of Environmental Protection, John Fitch Plaza, P.O. Box 2807, Trenton, New Jersey 08625.

* * * * *

[FR Doc.77-21020 Filed 7-20-77;8:45 am]

64

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Applicability Dates

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This action incorporates into the regulations the dates on which the standards of performance are applicable. The dates were not a part of the regulations at the time of their promulgation and considerable confusion exists over when the standards apply. This action removes the confusion and makes future enforcement of the standards easier.

EFFECTIVE DATE: August 24, 1977.

FOR FURTHER INFORMATION CONTACT:

Don. R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: Section 111 of the Clean Air Act provides that "new source" under that section means "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance which will be applicable to such source." Thus, for standards of performance under section 111, the proposal date (or, in the event there was no proposal, the promulgation date) of a standard constitutes its applicability date. While this information is contained in the "Applicability" section (§ 60.2) of the General Provisions, the Agency has not, until now, incorporated in the regulations the specific applicability date(s) for each standard.

The absence of these dates from the various regulations has led to some confusion. The most frequent mistake is for the applicability date to be confused with the effective date. The effective date is the day on which the regulation becomes law (usually the day the final regulation is published in the FEDERAL REGISTER). The effective date has customarily been noted in the preamble to the final regulation when it appears in the FEDERAL REGISTER. A regulation, then, usually becomes effective upon promulgation and applies to sources constructed or modified after the proposal date.

In view of past confusion and the growing number of regulations, including revisions and amendments, the Agency has decided to hereafter incorporate the applicability date(s) under the "Applicability and designation of affected facility" section of each subpart. This action should serve to clarify which facilities are affected by these regulations. This amendment provides clarification of the applicability dates only for the standards promulgated to date. An applicability statement will be added to regulations under proposal and to future regulations at the time of promulgation.

MISCELLANEOUS

As this action has no regulatory impact, but only sets forth applicability dates for the purpose of clarification, public participation was judged unnecessary.

(Secs. 111 and 301(a) of the Clean Air Act; sec. 4(a) of Pub. L. 91-604, 84 Stat. 1683; sec. 2 of Pub. L. 90-148, 81 Stat. 504 (42 U.S.C. 1857c-6, 1857g(a)).)

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Analysis under Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: July 18, 1977.

BARBARA BLUM,
Acting Administrator.

40 CFR Part 60 is amended by revising Subparts D through AA as follows:

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators

1. Section 60.40 is revised as follows:

§ 60.40 Applicability and designation of affected facility.

(a) The affected facilities to which the provisions of this subpart apply are:

(1) Each fossil-fuel-fired steam generating unit of more than 73 megawatts heat input rate (250 million Btu per hour).

(2) Each fossil-fuel and wood-residue-fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 megawatts (250 million Btu per hour).

(b) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.

(c) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

Subpart E—Standards of Performance for Incinerators

2. Section 60.50 is revised as follows:

§ 60.50 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to each incinerator of more than 45 metric tons per day charging rate (50 tons/day), which is the affected facility.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

Subpart F—Standards of Performance for Portland Cement Plants

3. Section 60.60 is revised as follows:

§ 60.60 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in portland cement plants: kiln, clinker cooler, raw mill system, finish mill system, raw mill dryer, raw material storage, clinker storage, finished product storage, conveyor transfer points, bagging and bulk loading and unloading systems.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

Subpart G—Standards of Performance for Nitric Acid Plants

4. Section 60.70 is revised as follows:

§ 60.70 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to each nitric acid production unit, which is the affected facility.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

Subpart H—Standards of Performance for Sulfuric Acid Plants

5. Section 60.80 is revised as follows:

§ 60.80 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to each sulfuric acid production unit, which is the affected facility.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

Subpart I—Standards of Performance for Asphalt Concrete Plants

6. Section 60.90 is revised as follows:

§ 60.90 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is each asphalt concrete plant. For the purpose of this subpart, an asphalt concrete plant is comprised only of any combination of the following: dryers; systems for screening, handling, storing, and weighing hot aggregate; systems for loading, transferring, and storing mineral filler; systems for mixing asphalt concrete; and the loading, transfer, and storage systems associated with emission control systems.

Subpart J—Standards of Performance for Petroleum Refineries

7. Section 60.100 is revised as follows:

§ 60.100 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fluid catalytic cracking unit incinerator-waste heat boilers, and fuel gas combustion devices.

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids

8. Section 60.110 is revised as follows:

§ 60.110 Applicability and designation of affected facility.

(a) Except as provided in § 60.110(b), the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,412 liters (40,000 gallons).

(b) This subpart does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

(c) Subject to the requirements of this subpart is any facility under paragraph (a) of this section which:

(1) Has a capacity greater than 151,412 liters (40,000 gallons), but not exceeding 245,000 liters (65,000 gallons, and commences construction or modification after March 8, 1974.

(2) Has a capacity greater than 245,000 liter (65,000 gallons), and commences construction or modification after June 11, 1973.

Subpart L—Standards of Performance for Secondary Lead Smelters

9. Section 60.120 is revised as follows:

§ 60.120 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in secondary lead smelters: pot furnaces of more than 250 kg (550 lb) charging capacity, blast (cupola) furnaces, and reverberatory furnaces.

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

Subpart M—Standards of Performance for Secondary Brass and Bronze Ingot Production Plants

10. Section 60.130 is revised as follows:

§ 60.130 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in secondary brass or bronze ingot production plants: reverberatory and electric furnaces of 1,000 kg (2,205 lb) or greater production capacity and blast (cupola) furnaces of 250 kg/hr (550 lb/hr) or greater production capacity.

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

Subpart N—Standards of Performance for Iron and Steel Plants

11. Section 60.140 is revised as follows:

§ 60.140 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is each basic oxygen process furnace.

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

Subpart O—Standards of Performance for Sewage Treatment Plants

12. Section 60.150 is revised as follows:

§ 60.150 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is each incinerator which burns the sludge produced by municipal sewage treatment facilities.

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

Subpart P—Standards of Performance for Primary Copper Smelters

13. Section 60.160 is revised as follows:

§ 60.160 Applicability and designation of affected facility.

(a) The provisions of this subpart are aplicable to the following affected facilities in primary copper smelters: dryer, roaster, smelting furnace, and copper converter.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 16, 1974, is subject to the requirements of this subpart.

Subpart Q—Standards of Performance for Primary Zinc Smelters

14. Section 60.170 is revised as follows:

§ 60.170 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in primary zinc smelters: roaster and sintering machine.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 16, 1974, is subject to the requirements of this subpart.

Subpart R—Standards of Performance for Primary Lead Smelters

15. Section 60.180 is revised as follows:

§ 60.180 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in primary lead smelters: sintering machine, sintering machine discharge end, blast furnace, dross reverberatory furnace, electric smelting furnace, and converter.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 16, 1974, is subject to the requirements of this subpart.

Subpart S—Standards of Performance for Primary Aluminum Reduction Plants

16. Section 60.190 is revised as follows:

§ 60.190 Applicability and designation of affected facility.

(a) The affected facilities in primary aluminum reduction plants to which this subpart applies are potroom groups and anode bake plants.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 23, 1974, is subject to the requirements of this subpart.

Subpart T—Standards of Performance for the Phosphate Fertilizer Industry: Wet-Process Phosphoric Acid Plants

17. Section 60.200 is revised as follows:

§ 60.200 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is each wet-process phosphoric acid plant. For the purpose of this subpart, the affected facility includes any combination of: reactors, filters, evaporators, and hotwells.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 22, 1974, is subject to the requirements of this subpart.

Subpart U—Standards of Performance for the Phosphate Fertilizer Industry: Superphosphoric Acid Plants

18. Section 60.210 is revised as follows:

§ 60.210 Applicability and designation of affected facility..

(a) The affected facility to which the provisions of this subpart apply is each superphosphoric acid plant. For the purpose of this subpart, the affected facility includes any combination of: evaporators, hotwells, acid sumps, and cooling tanks.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 22, 1974, is subject to the requirements of this subpart.

Subpart V—Standards of Performance for the Phosphate Fertilizer Industry: Diammonium Phosphate Plants

19. Section 60.220 is revised as follows:

§ 60.220 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is each granular diammonium phosphate plant. For the purpose of this subpart, the affected facility includes any combination of: reactors, granulators, dryers, coolers, screens, and mills.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 22, 1974, is subject to the requirements of this subpart.

Subpart W—Standards of Performance for the Phosphate Fertilizer Industry: Triple Superphosphate Plants

20. Section 60.230 is revised as follows:

§ 60.230 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is each triple superphosphate plant. For the purpose of this subpart, the affected facility includes any combination of: mixers, curing belts (dens), reactors, granulators, dryers, cookers, screens, mills, and facilities which store run-of-pile triple superphosphate.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 22, 1974, is subject to the requirements of this subpart.

Subpart X—Standards of Performance for the Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities

21. Section 60.240 is revised as follows:

§ 60.240 Applicability and designation of affected facility.

(a) The affected facility to which the provisions of this subpart apply is each granular triple superphosphate storage facility. For the purpose of this subpart, the affected facility includes any combination of: storage or curing piles, conveyors, elevators, screens, and mills.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 22, 1974, is subject to the requirements of this subpart.

Subpart Y—Standards of Performance for Coal Preparation Plants

22. Section 60.250 is revised as follows:

§ 60.250 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to any of the following affected facilities in coal preparation plants which process more than 200 tons per day: thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 21, 1974, is subject to the requirements of this subpart.

Subpart Z—Standards of Performance for Ferroalloy Production Facilities

23. Section 60.260 is revised as follows:

§ 60.260 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities: electric submerged arc furnaces which produce silicon metal, ferrosilicon, calcium silicon, silicomanganese zirconium, ferrochrome silicon, silvery iron, high-carbon ferrochrome, charge chrome, standard ferromanganese, silicomanganese, ferromanganese silicon, or calcium carbide; and dust-handling equipment.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 21, 1974, is subject to the requirements of this subpart.

Subpart AA—Standards of Performance for Steel Plants: Electric Arc Furnaces

24. Section 60.270 is revised as follows:

§ 60.270 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in steel plants: electric arc furnaces and dust-handling equipment.

(b) Any facility under paragraph (a) of this section that commences construction or modification after October 24, 1974, is subject to the requirements of this subpart.

(Secs. 111 and 301(a), Clean Air Act as amended (42 U.S.C. 1857c-6, 1857g(a)).)

[FR Doc.77-21230 Filed 7-22-77;8:45 am]

65

Title 40—Protection of the Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 742-5]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Petroleum Refinery Fluid Catalytic Cracking Unit Catalyst Regenerators

Correction

In FR Doc. 77-18129, appearing at page 32426, in Part VI of the issue of Friday, June 24, 1977, the EFFECTIVE DATE should be changed to read "June 24, 1977"

[FRL-752-2]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Units and Abbreviations

Correction

In FR Doc. 77-20557, appearing on page 37000 in the issue for Tuesday, July 19, 1977, in the second column, § 60.3(a) should be changed so that the last abbreviation reads as follows:

"μg—microgram—10^{-6} gram".

66

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Petroleum Refinery Fluid Catalytic Cracking Unit Catalyst Regenerators; Correction

AGENCY: Environmental Protection Agency.

ACTION: Correction.

SUMMARY: This document corrects the final rule that appeared at page 32425 in the FEDERAL REGISTER of Friday, June 24, 1977 (FR Doc. 77-18129).

EFFECTIVE DATE: August 4, 1977.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone 919-541-5271.

Dated: July 29, 1977.

ERIC O. STORK,
Acting Assistant Administrator for Air and Waste Management.

In FR Doc. 77-18129 appearing on page 32425 in the FEDERAL REGISTER of Friday, June 24, 1977, §§ 60.102(a)(2) and 60.105(e)(1) on page 32427 are corrected as follows:

1. In § 60.102(a)(2), the word "period" is added in the fourth line immediately following the words "in any one-hour."

2. In § 60.105(e)(1), "hourly period" in the first line is corrected to read "one-hour periods."

(Sec. 111, 114, 301(a) of the Clean Air Act as amended [42 U.S.C. 1857c-6, 1857c-9, 1857g (a)]).

[FR Doc.77-22357 Filed 8-3-77;8:45 am]

67

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Amendments to Subpart D; Correction

AGENCY: Environmental Protection Agency.

ACTION: Correction.

SUMMARY: This document corrects the final rule that appeared at page 51397 in the FEDERAL REGISTER of Monday, November 22, 1976 (FR Doc. 76-33966).

EFFECTIVE DATE: August 15, 1977.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711, Telephone No. 919-541-5271.

Dated August 8, 1977.

EDWARD F. TUERK,
Acting Assistant Administrator, for Air and Waste Management.

In FR Doc. 76-33966, §§ 60.45(f)(4) and 60.45(f)(5) on page 51399 are corrected as follows:

§ 60.45 [Amended]

1. In § 60.45(f)(4)(iii) "F_c=0.384 scm CO_2/J" in the fourth line is corrected to read "$F_c=0.384\times10^{-7}$ scm CO_2/J."

2. In § 60.45(f)(4)(iv) a left parenthesis is inserted in the second line between "dscm/J" and "8,740."

3. § 60.45(f)(4)(v) is corrected to read as follows:

§ 60.45 Emission and fuel monitoring.

* * * * * *

(f) * * *

(4) * * *

(v) For bark $F=2.589\times10^{-7}$ dscm/J (9,640 dscf/million Btu) and $F_c=0.500\times10^{-7}$ scm CO_2/J (1,860 scf CO_2/million Btu). For wood residue other than bark $F=2.492\times10^{-7}$ dscm/J (9,280 dscf/million Btu) and $F_c=0.494\times10^{-7}$ scm CO_2/J (1,840 scf CO_2/million Btu).

* * * * * *

4. In § 60.45(f)(5) the F factor and F_c factor equations in SI units are corrected to read as follows:

$$F=10^{-6}\frac{[227.2\ (\text{pct. H})+95.5\ (\text{pct. C})+35.6\ (\text{pct. S})+8.7\ (\text{pct. N})-28.7\ (\text{pct. O})]}{\text{GCV}}.$$

$$F_c=\frac{2.0\times10^{-6}\ (\text{pct. C})}{\text{GCV}}.$$

(Sec. 111, 114, 301(a) of the Clean Air Act as amended (42 U.S.C. 1857c-6, 1857c-9, 1857g(a)).)

[FR Doc.77-23402 Filed 8-12-77;8:45 am]

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 775-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

Authority Citations; Revision

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This action revises the authority citations for Standards of Performance for New Stationary Sources and National Emission Standards for Hazardous Air Pollutants. The revision adopts a method recommended by the FEDERAL REGISTER for identifying which sections are enacted under which statutory authority, making the citations more useful to the reader.

EFFECTIVE DATE: August 17, 1977.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: This action is being taken in accordance with the requirements of 1 CFR 21.43 and is authorized under section 301(a) of the Clean Air Act, as amended, 42 U.S.C. 1857g(a). Because the amendments are clerical in nature and affect no substantive rights or requirements, the Administrator finds it unnecessary to propose and invite public comment.

Dated: August 12, 1977.

DOUGLAS M. COSTLE,
Administrator.

Parts 60 and 61 of Chapter I, Title 40 of the Code of Federal Regulations are revised as follows:

1. The authority citation following the table of sections in Part 60 is revised to read as follows:

AUTHORITY: Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 1857c-6, 1857g (a)), unless otherwise noted.

2. Following §§ 60.10 and 60.24(g) the following authority citation is added:

(Sec. 116 of the Clean Air Act as amended (42 U.S.C. 1857d-1).)

3. Following §§ 60.7, 60.8, 60.9, 60.11, 60.13, 60.45, 60.46, 60.53, 60.54, 60.63, 60.64, 60.73, 60.74, 60.84, 60.85, 60.93, 60.105, 60.106, 60.113, 60.123, 60.133, 60.144, 60.153, 60.154, 60.165, 60.166, 60.175, 60.176, 60.185, 60.186, 60.194, 60.195, 60.203, 60.204, 60.213, 60.214, 60.223, 60.224, 60.233, 60.234, 60.243, 60.244, 60.253, 60.254, 60.264, 60.265, 60.266, 60.273, 60.274, 60.275 and Appendices A, B, C, and D, the following authority citation is added:

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9).)

4. The authority citation following the table of sections in Part 61 is revised to read as follows:

AUTHORITY: Sec. 112, 301(a) of the Clean Air Act as amended (42 U.S.C. 1857c-7, 1857g (a)), unless otherwise noted.

5. Following § 61.16, the following authority citation is added:

(Sec. 116 of the Clean Air Act as amended (42 U.S.C. 1857d-1).)

6. Following §§ 61.09, 61.10, 61.12, 61.13, 61.14, 61.15, 61.24, 61.33, 61.34, 61.43, 61.44, 61.53, 61.54, 61.55, 61.67, 61.68, 61.69, 61.70, 61.71, and Appendices A and B, the following authority citation is added:

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9).)

[FR Doc.77-23827 Filed 8-16-77;8:45 am]

69

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Revision to Reference Methods 1–8

AGENCY: Environmental Protection Agency.

ACTION: Final Rule.

SUMMARY: This rule revises Reference Methods 1 through 8, the detailed requirements used to measure emissions from affected facilities to determine whether they are in compliance with a standard of performance. The methods were originally promulgated December 23, 1971, and since that time several revisions became apparent which would clarify, correct and improve the methods. These revisions make the methods easier to use, and improve their accuracy and reliability.

EFFECTIVE DATE: September 19, 1977.

ADDRESSES: Copies of the comment letters are available for public inspection and copying at the U.S. Environmental Protection Agency, Public Information Reference Unit (EPA Library), Room 2922, 401 M Street, S.W., Washington, D.C. 20460. A summary of the comments and EPA's responses may be obtained upon written request from the EPA Public Information Center (PM-215), 401 M Street, S.W., Washington, D.C. 20460 (specify "Public Comment Summary: Revisions to Reference Methods 1–8 in Appendix A of Standards of Performance for New Stationary Sources").

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone No. 919–541–5271.

SUPPLEMENTARY INFORMATION: The amendments were proposed on June 8, 1976 (40 FR 23060). A total of 55 comment letters were received during the comment period—34 from industry, 15 from governmental agencies, and 6 from other interested parties. They contained numerous suggestions which were incorporated in the final revisions.

Changes common to all eight of the reference methods are: (1) the clarification of procedures and equipment specifications resulting from the comments, (2) the addition of guidelines for alternative procedures and equipment to make prior approval of the Administrator unnecessary and (3) the addition of an introduction to each reference method discussing the general use of the method and delineating the procedure for using alternative methods and equipment.

Specific changes to the methods are:

METHOD 1

1. The provision for the use of more than two traverse diameters, when specified by the Administrator, has been deleted. If one traverse diameter is in a plane containing the greatest expected concentration variation, the intended purpose of the deleted paragraph will be fulfilled.

2. Based on recent data from Fluidyne (Particulate Sampling Strategies for Large Power Plants Including Nonuniform Flow, EPA–600/2–76–170, June 1976) and Entropy Environmentalists (Determination of the Optimum Number of Traverse Points: An Analysis of Method 1 Criteria (draft), Contract No. 68–01–3172), the number of traverse points for velocity measurements has been reduced and the 2:1 length to width ratio requirement for cross-sectional layout of rectangular ducts has been replaced by a "balanced matrix" scheme.

3. Guidelines for sampling in stacks containing cyclonic flow and stacks smaller than about 0.31 meter in diameter or 0.071 m^2 in cross-sectional area will be published at a later date.

4. Clarification has been made as to when a check for cyclonic flow is necessary; also, the suggested procedure for determination of unacceptable flow conditions has been revised.

METHOD 2

1. The calibration of certain pitot tubes has been made optional. Appropriate construction and application guidelines have been included.

2. A detailed calibration procedure for temperature gauges has been included.

3. A leak check procedure for pitot lines has been included.

METHOD 3

1. The applicablility of the method has been confined to fossil-fuel combustion processes and to other processes where it has been determined that components other than O_2, CO_2, CO, and N_2 are not present in concentrations sufficient to affect the final results.

2. Based on recent research information (Particulate Sampling Strategies for Large Power Plants Including Nonuniform Flow, EPA–600/2–76–170, June 1976), the requirement for proportional sampling has been dropped and replaced with the requirement for constant rate sampling. Proportional and constant rate sampling have been found to give essentially the same result.

3. The "three consecutive" requirement has been replaced by "any three" for the determination of molecular weight, CO_2 and O_2.

4. The equation for excess air has been revised to account for the presence of CO.

5. A clearer distinction has been made between molecular weight determination and emission rate correction factor determination.

6. Single point, integrated sampling has been included.

METHOD 4

1. The sampling time of 1 hour has been changed to a total sampling time which will span the length of time the pollutant emission rate is being determined or such time as specified in an applicable subpart of the standards.

2. The requirement for proportional sampling has been dropped and replaced with the requirement for constant rate sampling.

3. The leak check before the test run has been made optional; the leak check after the run remains mandatory.

METHOD 5

1. The following alternatives have been included in the method:

a. The use of metal probe liners.

b. The use of other materials of construction for filter holders and probe liner parts.

c. The use of polyethylene wash bottles and sample storage containers.

d. The use of desiccants other than silica gel or calcium sulfate, when appropriate.

e. The use of stopcock grease other than silicone grease, when appropriate.

f. The drying of filters and probe-filter catches at elevated temperatures, when appropriate.

g. The combining of the filter and probe washes into one container.

2. The leak check prior to a test run has been made optional. The post-test leak check remains mandatory. A method for correcting sample volume for excessive leakage rates has been included.

3. Detailed leak check and calibration procedures for the metering system have been included.

METHOD 6

1. Possible interfering agents of the method have been delineated.

2. The options of: (a) using a Method 8 impinger system, or (b) determining SO_3 simultaneously with particulate matter, have been included in the method.

3. Based on recent research data, the requirement for proportional sampling has been dropped and replaced with the requirement for constant rate sampling.

4. Tests have shown that isopropanol obtained from commercial sources occasionally has peroxide impurities that will cause erroneously low SO_2 measurements. Therefore, a test for detecting peroxides in isopropanol has been included in the method.

5. The leak check before the test run has been made optional; the leak check after the run remains mandatory.

6. A detailed calibration procedure for the metering system has been included in the method.

METHOD 7

1. For variable wave length spectrophotometers, a scanning procedure for determining the point of maximum absorbance has been incorporated as an option.

METHOD 8

1. Known interfering compounds have been listed to avoid misapplication of the method.

2. The determination of filterable particulate matter (including acid mist) simultaneously with SO_3 and SO_2 has been allowed where applicable.

3. Since occassionally some commercially available quantities of isopropanol

have peroxide impurities that will cause erroneously high sulfuric acid mist measurements, a test for peroxides in isopropanol has been included in the method.

4. The gravimetric technique for moisture content (rather than volumetric) has been specified because a mixture of isopropyl alcohol and water will have a volume less than the sum of the volumes of its content.

5. A closer correspondence has been made between similar parts of Methods 8 and 5.

MISCELLANEOUS

Several commenters questioned the meaning of the term "subject to the approval of the Administrator" in relation to using alternate test methods and procedures. As defined in § 60.2 of subpart A, the "Administrator" includes any authorized representative of the Administrator of the Environmental Protection Agency. Authorized representatives are EPA officials in EPA Regional Offices or State, local, and regional governmental officials who have been delegated the responsibility of enforcing regulations under 40 CFR 60. These officials in consultation with other staff members familiar with technical aspects of source testing will render decisions regarding acceptable alternate test procedures.

In accordance with section 117 of the Act, publication of these methods was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

(Secs. 111, 114 and 301(a) of the Clean Air Act, sec. 4(a) of Pub. L. No. 91-604, 84 Stat. 1683; sec. 4(a) of Pub. L. No. 91-604, 84 Stat. 1687; sec. 2 of Pub. L. No. 90-148, 81 Stat. 504 [42 U.S.C. 1857c-6, 1857c-9, 1857g(a)].)

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Analysis under Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: August 10, 1977.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I of Title 40 of the Code of Federal Regulations is amended by revising Methods 1 through 8 of Appendix A—Reference Methods as follows:

APPENDIX A—REFERENCE METHODS

The reference methods in this appendix are referred to in § 60.8 (Performance Tests) and § 60.11 (Compliance With Standards and Maintenance Requirements) of 40 CFR Part 60, Subpart A (General Provisions). Specific uses of these reference methods are described in the standards of performance contained in the subparts, beginning with Subpart D.

Within each standard of performance, a section titled "Test Methods and Procedures" is provided to (1) identify the test methods applicable to the facility subject to the respective standard and (2) identify any special instructions or conditions to be followed when applying a method to the respective facility. Such instructions (for example, establish sampling rates, volumes, or temperatures) are to be used either in addition to, or as a substitute for procedures in a reference method. Similarly, for sources subject to emission monitoring requirements, specific instructions pertaining to any use of a reference method are provided in the subpart or in Appendix B.

Inclusion of methods in this appendix is not intended as an endorsement or denial of their applicability to sources that are not subject to standards of performance. The methods are potentially applicable to other sources; however, applicability should be confirmed by careful and appropriate evaluation of the conditions prevalent at such sources.

The approach followed in the formulation of the reference methods involves specifications for equipment, procedures, and performance. In concept, a performance specification approach would be preferable in all methods because this allows the greatest flexibility to the user. In practice, however, this approach is impractical in most cases because performance specifications cannot be established. Most of the methods described herein, therefore, involve specific equipment specifications and procedures, and only a few methods in this appendix rely on performance criteria.

Minor changes in the reference methods should not necessarily affect the validity of the results and it is recognized that alternative and equivalent methods exist. Section 60.8 provides authority for the Administrator to specify or approve (1) equivalent methods, (2) *alternative methods*, and (3) *minor changes* in the methodology of the reference methods. It should be clearly understood that unless otherwise identified all such methods and changes must have prior approval of the Administrator. An owner employing such methods or deviations from the reference methods without obtaining prior approval does so at the risk of subsequent disapproval and retesting with approved methods.

Within the reference methods, certain specific equipment or procedures are recognized as being acceptable or potentially acceptable and are specifically identified in the methods. The items identified as acceptable options may be used without approval but must be identified in the test report. The potentially approvable options are cited as "subject to the approval of the Administrator" or as "or equivalent." Such potentially approvable techniques or alternatives may be used at the discretion of the owner without prior approval. However, detailed descriptions for applying these potentially approvable techniques or alternatives are not provided in the reference methods. Also, the potentially approvable options are not necessarily acceptable in all applications. Therefore, an owner electing to use such potentially approvable techniques or alternatives is responsible for: (1) assuring that the techniques or alternatives are in fact applicable and are properly executed; (2) including a written description of the alternative method in the test report (the written method must be clear and must be capable of being performed without additional instruction, and the degree of detail should be similar to the detail contained in the reference methods); and (3) providing any rationale or supporting data necessary to show the validity of the alternative in the particular application. Failure to meet these requirements can result in the Administrator's disapproval of the alternative.

METHOD 1—SAMPLE AND VELOCITY TRAVERSES FOR STATIONARY SOURCES

1. *Principle and Applicability*

1.1 Principle. To aid in the representative measurement of pollutant emissions and/or total volumetric flow rate from a stationary source, a measurement site where the effluent stream is flowing in a known direction is selected, and the cross-section of the stack is divided into a number of equal areas. A traverse point is then located within each of these equal areas.

1.2 Applicability. This method is applicable to flowing gas streams in ducts, stacks, and flues. The method cannot be used when: (1) flow is cyclonic or swirling (see Section 2.4), (2) a stack is smaller than about 0.30 meter (12 in.) in diameter, or 0.071 m^2 (113 in^2) in cross-sectional area, or (3) the measurement site is less than two stack or duct diameters downstream or less than a half diameter upstream from a flow disturbance.

The requirements of this method must be considered before construction of a new facility from which emissions will be measured; failure to do so may require subsequent alterations to the stack or deviation from the standard procedure. Cases involving variants are subject to approval by the Administrator, U.S. Environmental Protection Agency.

2. *Procedure*

2.1 Selection of Measurement Site. Sampling or velocity measurement is performed at a site located at least eight stack or duct diameters downstream and two diameters upstream from any flow disturbance such as a bend, expansion, or contraction in the stack, or from a visible flame. If necessary, an alternative location may be selected, at a position at least two stack or duct diameters downstream and a half diameter upstream from any flow disturbance. For a rectangular cross section, an equivalent diameter (D_e) shall be calculated from the following equation, to determine the upstream and downstream distances.

$$D_e = \frac{2LW}{L+W}$$

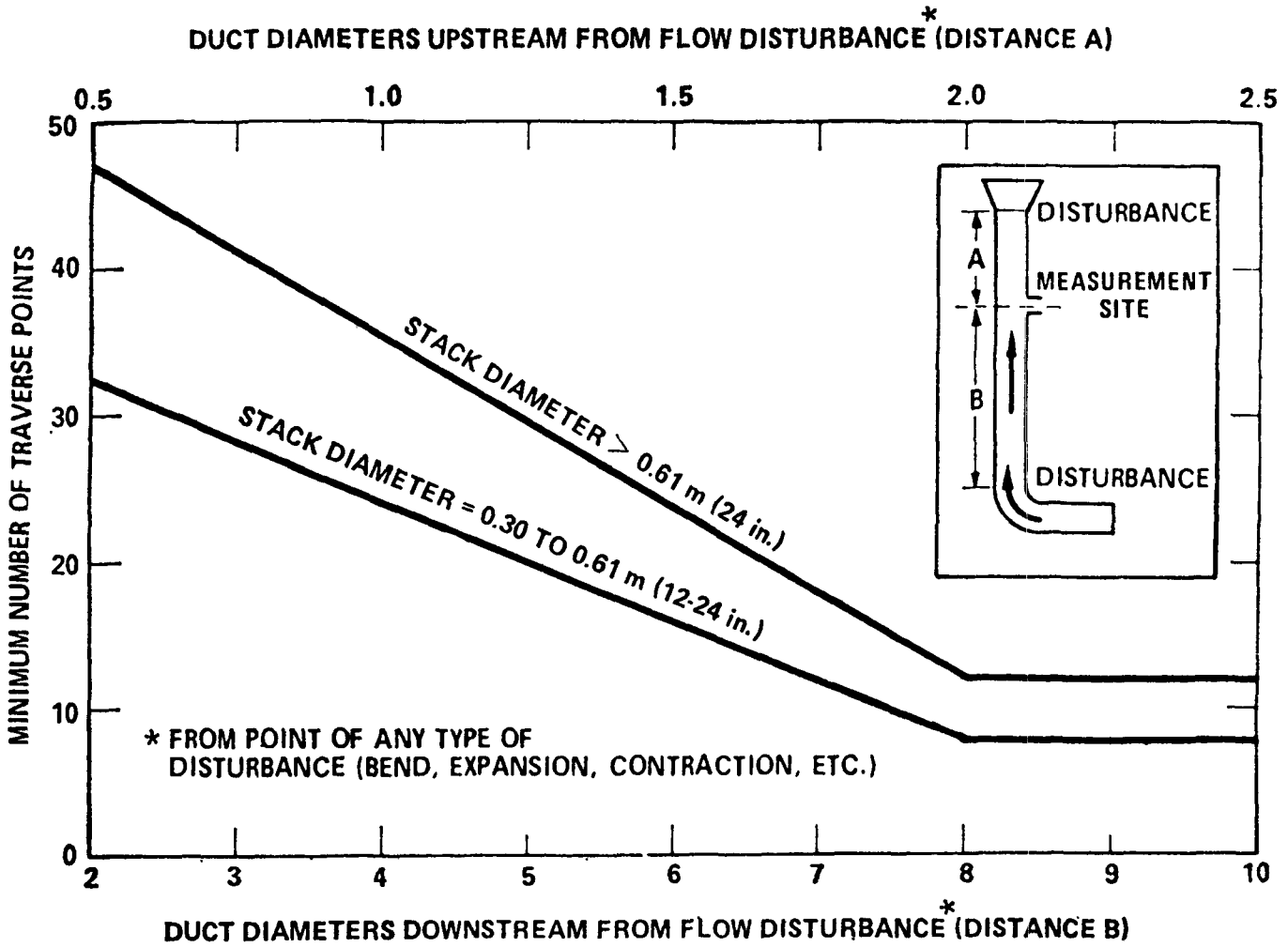


Figure 1-1. Minimum number of traverse points for particulate traverses.

where L=length and W=width.

2.2 Determining the Number of Traverse Points.

2.2.1 Particulate Traverses. When the eight- and two-diameter criterion can be met, the minimum number of traverse points shall be: (1) twelve, for circular or rectangular stacks with diameters (or equivalent diameters) greater than 0.61 meter (24 in.); (2) eight, for circular stacks with diameters between 0.30 and 0.61 meter (12–24 in.); (3) nine, for rectangular stacks with equivalent diameters between 0.30 and 0.61 meter (12–24 in.).

When the eight- and two-diameter criterion cannot be met, the minimum number of traverse points is determined from Figure 1-1. Before referring to the figure, however, determine the distances from the chosen measurement site to the nearest upstream and downstream disturbances, and divide each distance by the stack diameter or equivalent diameter, to determine the distance in terms of the number of duct diameters. Then, determine from Figure 1-1 the minimum number of traverse points that corresponds: (1) to the number of duct diameters upstream; and (2) to the number of diameters downstream. Select the higher of the two minimum numbers of traverse points, or a greater value, so that for circular stacks the number is a multiple of 4, and for rectangular stacks, the number is one of those shown in Table 1-1.

TABLE 1-1. *Cross-sectional layout for rectangular stacks*

Number of traverse points:	*Matrix layout*
9	3x3
12	4x3
16	4x4
20	5x4
25	5x5
30	6x5
36	6x6
42	7x6
49	7x7

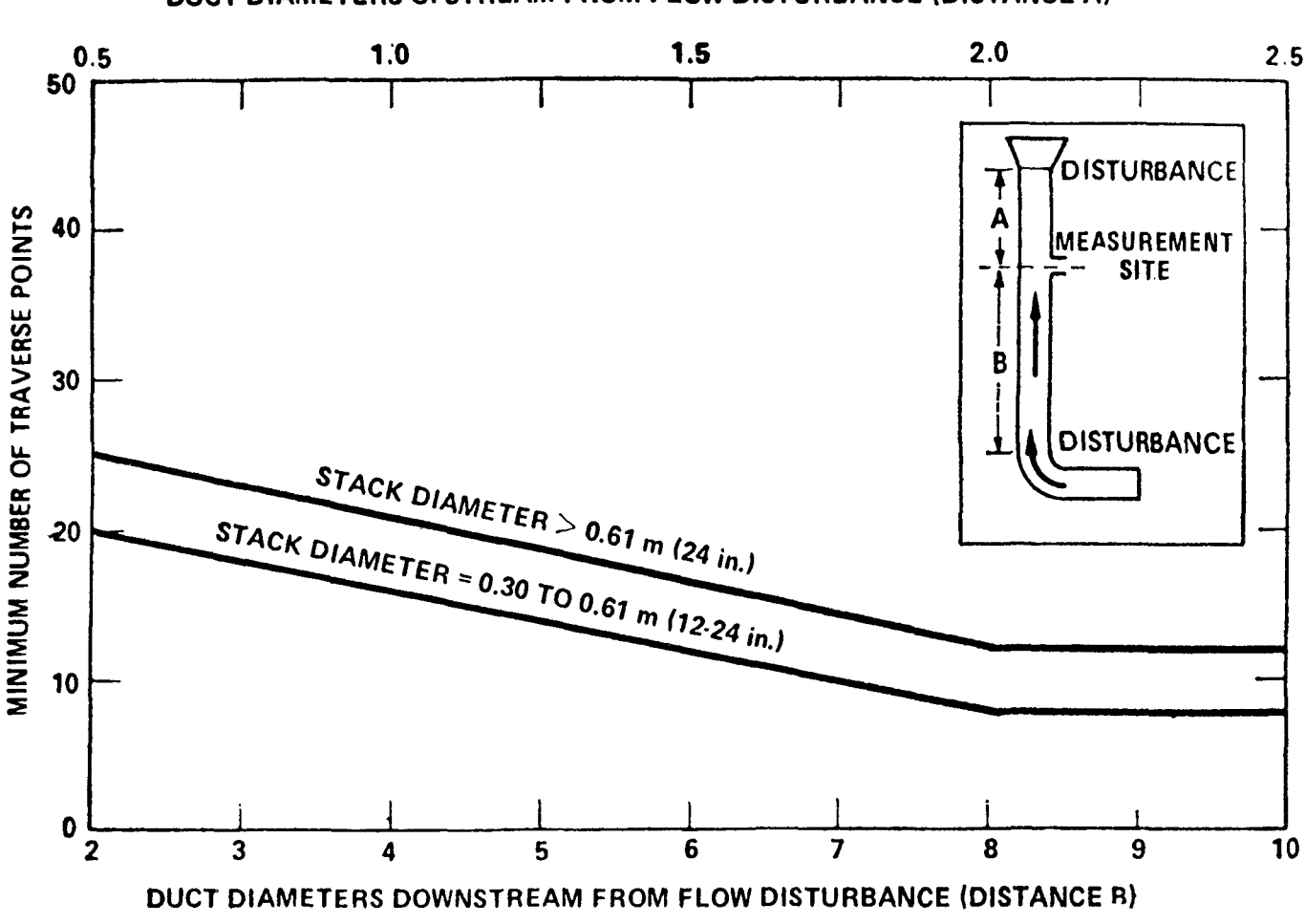


Figure 1-2. Minimum number of traverse points for velocity (nonparticulate) traverses.

2.2.2 Velocity (Non-Particulate) Traverses. When velocity or volumetric flow rate is to be determined (but not particulate matter), the same procedure as that for particulate traverses (Section 2.2.1) is followed, except that Figure 1-2 may be used instead of Figure 1-1.

2.3 Cross-Sectional Layout and Location of Traverse Points.

2.3.1 Circular Stacks. Locate the traverse points on two perpendicular diameters according to Table 1-2 and the example shown in Figure 1-3. Any equation (for examples, see Citations 2 and 3 in the Bibliography) that gives the same values as those in Table 1-2 may be used in lieu of Table 1-2.

For particulate traverses, one of the diameters must be in a plane containing the greatest expected concentration variation, e.g., after bends, one diameter shall be in the plane of the bend. This requirement becomes less critical as the distance from the disturbance increases; therefore, other diameter locations may be used, subject to approval of the Administrator.

In addition, for stacks having diameters greater than 0.61 m (24 in.) no traverse points shall be located within 2.5 centimeters (1.00 in.) of the stack walls; and for stack diameters equal to or less than 0.61 m (24 in.), no traverse points shall be located within 1.3 cm (0.50 in.) of the stack walls. To meet these criteria, observe the procedures given below.

2.3.1.1 Stacks With Diameters Greater Than 0.61 m (24 in.). When any of the traverse points as located in Section 2.3.1 fall within 2.5 cm (1.00 in.) of the stack walls, relocate them away from the stack walls to. (1) a distance of 2.5 cm (1.00 in.), or (2) a distance equal to the nozzle inside diameter, whichever is larger. These relocated traverse points (on each end of a diameter) shall be the "adjusted" traverse points.

Whenever two successive traverse points are combined to form a single adjusted traverse point, treat the adjusted point as two separate traverse points, both in the sampling (or velocity measurement) procedure, and in recording the data.

TRAVERSE POINT	DISTANCE, % of diameter
1	4.4
2	14.7
3	29.5
4	70.5
5	85.3
6	95.6

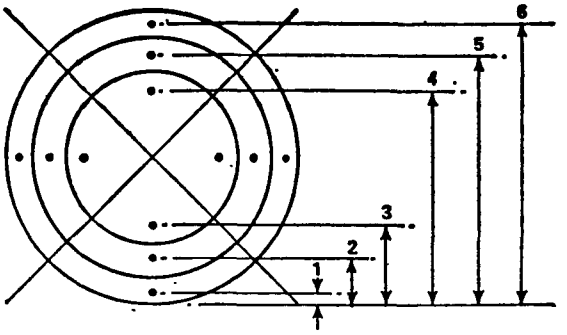


Figure 1-3. Example showing circular stack cross section divided into 12 equal areas, with location of traverse points indicated.

Table 1-2. LOCATION OF TRAVERSE POINTS IN CIRCULAR STACKS

(Percent of stack diameter from inside wall to traverse point)

Traverse point number on a diameter	Number of traverse points on a diameter											
	2	4	6	8	10	12	14	16	18	20	22	24
1	14.6	6.7	4.4	3.2	2.6	2.1	1.8	1.6	1.4	1.3	1.1	1.1
2	85.4	25.0	14.6	10.5	8.2	6.7	5.7	4.9	4.4	3.9	3.5	3.2
3		75.0	29.6	19.4	14.6	11.8	9.9	8.5	7.5	6.7	6.0	5.5
4		93.3	70.4	32.3	22.6	17.7	14.6	12.5	10.9	9.7	8.7	7.9
5			85.4	67.7	34.2	25.0	20.1	16.9	14.6	12.9	11.6	10.5
6			95.6	80.6	65.8	35.6	26.9	22.0	18.8	16.5	14.6	13.2
7				89.5	77.4	64.4	36.6	28.3	23.6	20.4	18.0	16.1
8				96.8	85.4	75.0	63.4	37.5	29.6	25.0	21.8	19.4
9					91.8	82.3	73.1	62.5	38.2	30.6	26.2	23.0
10					97.4	88.2	79.9	71.7	61.8	38.8	31.5	27.2
11						93.3	85.4	78.0	70.4	61.2	39.3	32.3
12						97.9	90.1	83.1	76.4	69.4	60.7	39.8
13							94.3	87.5	81.2	75.0	68.5	60.2
14							98.2	91.5	85.4	79.6	73.8	67.7
15								95.1	89.1	83.5	78.2	72.8
16								98.4	92.5	87.1	82.0	77.0
17									95.6	90.3	85.4	80.6
18									98.6	93.3	88.4	83.9
19										96.1	91.3	86.8
20										98.7	94.0	89.5
21											96.5	92.1
22											98.9	94.5
23												96.8
24												98.9

2.3.1.2 Stacks With Diameters Equal to or Less Than 0.61 m (24 in.). Follow the procedure in Section 2.3.1.1, noting only that any "adjusted" points should be relocated away from the stack walls to: (1) a distance of 1.3 cm (0.50 in.); or (2) a distance equal to the nozzle inside diameter, whichever is larger.

2.3.2 Rectangular Stacks. Determine the number of traverse points as explained in Sections 2.1 and 2.2 of this method. From Table 1-1, determine the grid configuration. Divide the stack cross-section into as many equal rectangular elemental areas as traverse points, and then locate a traverse point at the centroid of each equal area according to the example in Figure 1-4.

The situation of traverse points being too close to the stack walls is not expected to arise with rectangular stacks. If this problem should ever arise, the Administrator must be contacted for resolution of the matter.

2.4 Verification of Absence of Cyclonic Flow In most stationary sources, the direction of stack gas flow is essentially parallel to the stack walls. However, cyclonic flow may exist (1) after such devices as cyclones and inertial demisters following venturi scrubbers, or (2) in stacks having tangential inlets or other duct configurations which tend to induce swirling; in these instances, the presence or absence of cyclonic flow at the sampling location must be determined. The following techniques are acceptable for this determination.

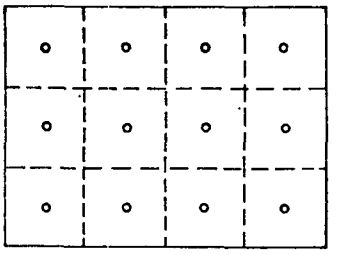


Figure 1-4. Example showing rectangular stack cross section divided into 12 equal areas, with a traverse point at centroid of each area.

Level and zero the manometer. Connect a Type S pitot tube to the manometer. Position the Type S pitot tube at each traverse point, in succession, so that the planes of the face openings of the pitot tube are perpendicular to the stack cross-sectional plane; when the Type S pitot tube is in this position, it is at "0° reference." Note the differential pressure (Δp) reading at each traverse point. If a null (zero) pitot reading is obtained at 0° reference at a given traverse point, an acceptable flow condition exists at that point. If the pitot reading is not zero at 0° reference, rotate the pitot tube (up to ±90° yaw angle), until a null reading is obtained. Carefully determine and record the value of the rotation angle (α) to the nearest degree. After the null technique has been applied at each traverse point, calculate the average of the absolute values of α; assign α values of 0° to those points for which no rotation was required, and include these in the overall average. If the average value of α is greater than 10°, the overall flow condition in the stack is unacceptable and alternative methodology, subject to the approval of the Administrator, must be used to perform accurate sample and velocity traverses.

3. *Bibliography*

1. Determining Dust Concentration in a Gas Stream. ASME. Performance Test Code No. 27. New York. 1957.

2. Devorkin, Howard, et al. Air Pollution Source Testing Manual. Air Pollution Control District. Los Angeles, CA. November 1963

3. Methods for Determination of Velocity, Volume, Dust and Mist Content of Gases. Western Precipitation Division of Joy Manufacturing Co. Los Angeles, CA. Bulletin WP-50. 1963.

4. Standard Method for Sampling Stacks for Particulate Matter. In: 1971 Book of ASTM Standards, Part 23. ASTM Designation D-2928-71. Philadelphia, Pa. 1971.

5. Hanson, H. A., et al. Particulate Sampling Strategies for Large Power Plants Including Nonuniform Flow. USEPA, ORD, ESRL, Research Triangle Park, N.C. EPA-600/2-76-170. June 1976.

6. Entropy Environmentalists, Inc. Determination of the Optimum Number of Sampling Points: An Analysis of Method 1 Criteria. Environmental Protection Agency. Research Triangle Park, N.C. EPA Contract No. 68-01-3172, Task 7.

METHOD 2—DETERMINATION OF STACK GAS VELOCITY AND VOLUMETRIC FLOW RATE (TYPE S PITOT TUBE)

1. *Principle and Applicability*

1.1 Principle. The average gas velocity in a stack is determined from the gas density and from measurement of the average velocity head with a Type S (Stausscheibe or reverse type) pitot tube.

1.2 Applicability. This method is applicable for measurement of the average velocity of a gas stream and for quantifying gas flow.

This procedure is not applicable at measurement sites which fail to meet the criteria of Method 1, Section 2.1. Also, the method cannot be used for direct measurement in cyclonic or swirling gas streams; Section 2.4 of Method 1 shows how to determine cyclonic or swirling flow conditions. When unacceptable conditions exist, alternative procedures, subject to the approval of the Administrator, U.S. Environmental Protection Agency, must be employed to make accurate flow rate determinations; examples of such alternative procedures are: (1) to install straightening vanes; (2) to calculate the total volumetric flow rate stoichiometrically, or (3) to move to another measurement site at which the flow is acceptable.

2. *Apparatus*

Specifications for the apparatus are given below. Any other apparatus that has been demonstrated (subject to approval of the Administrator) to be capable of meeting the specifications will be considered acceptable.

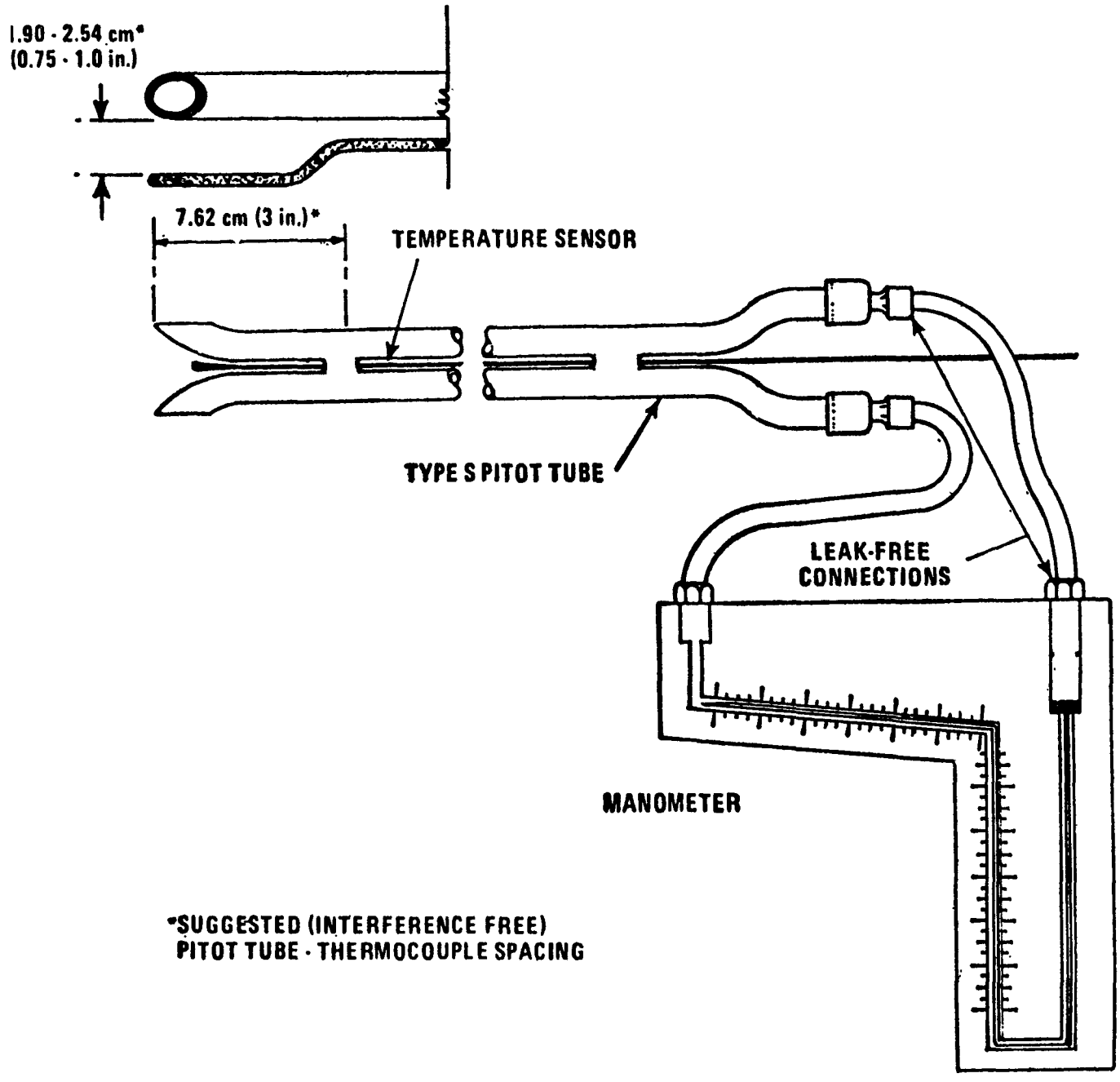


Figure 2-1. Type S pitot tube manometer assembly.

2.1 Type S Pitot Tube. The Type S pitot tube (Figure 2-1) shall be made of metal tubing (e.g., stainless steel). It is recommended that the external tubing diameter (dimension D_t, Figure 2-2b) be between 0.48 and 0.95 centimeters ($\frac{3}{16}$ and $\frac{3}{8}$ inch). There shall be an equal distance from the base of each leg of the pitot tube to its face-opening plane (dimensions P_A and P_B, Figure 2-2b); it is recommended that this distance be between 1.05 and 1.50 times the external tubing diameter. The face openings of the pitot tube shall, preferably, be aligned as shown in Figure 2-2; however, slight misalignments of the openings are permissible (see Figure 2-3).

The Type S pitot tube shall have a known coefficient, determined as outlined in Section 4. An identification number shall be assigned to the pitot tube; this number shall be permanently marked or engraved on the body of the tube.

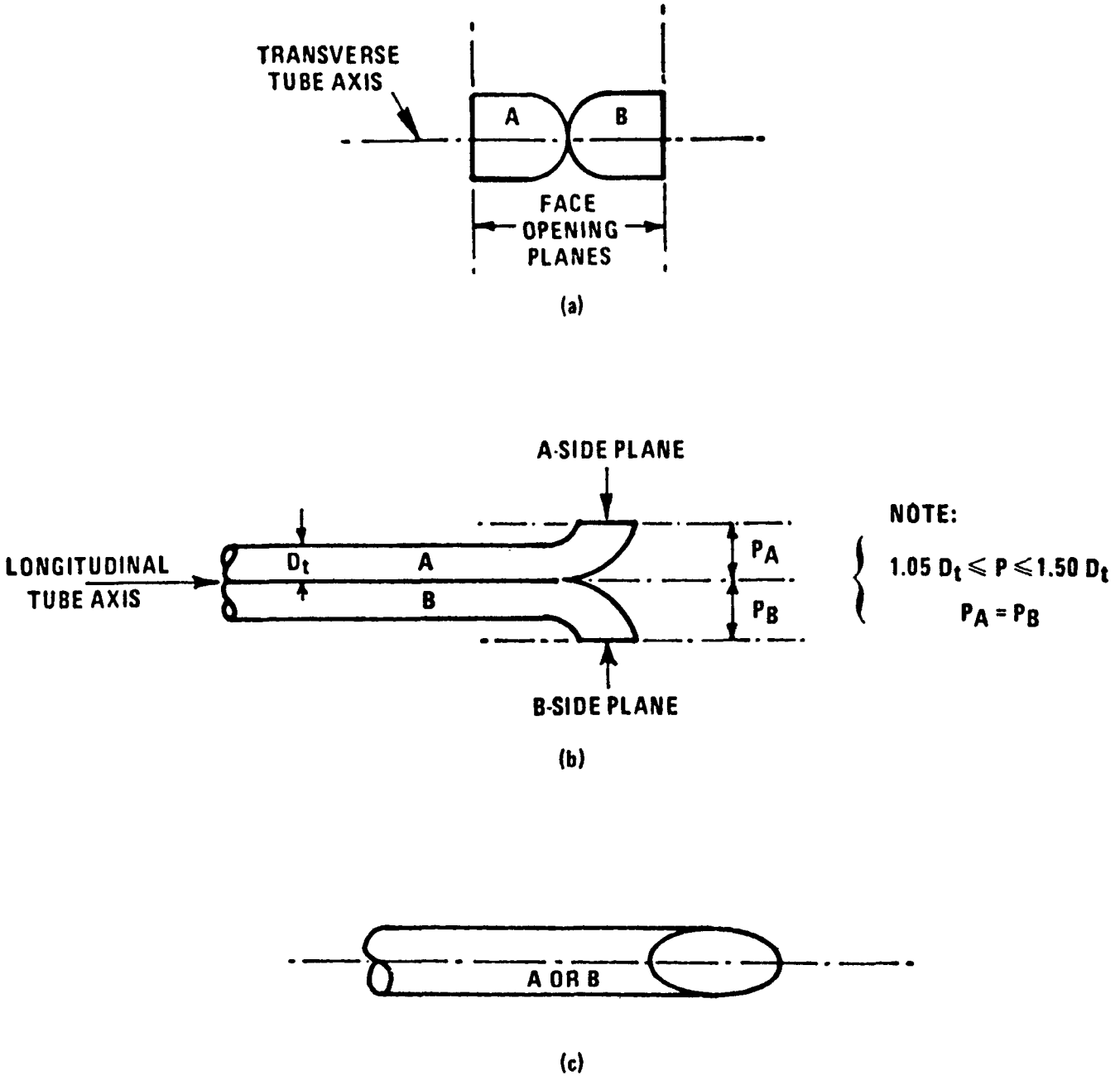


Figure 2-2. Properly constructed Type S pitot tube, shown in: (a) end view; face opening planes perpendicular to transverse axis; (b) top view; face opening planes parallel to longitudinal axis; (c) side view; both legs of equal length and centerlines coincident, when viewed from both sides. Baseline coefficient values of 0.84 may be assigned to pitot tubes constructed this way.

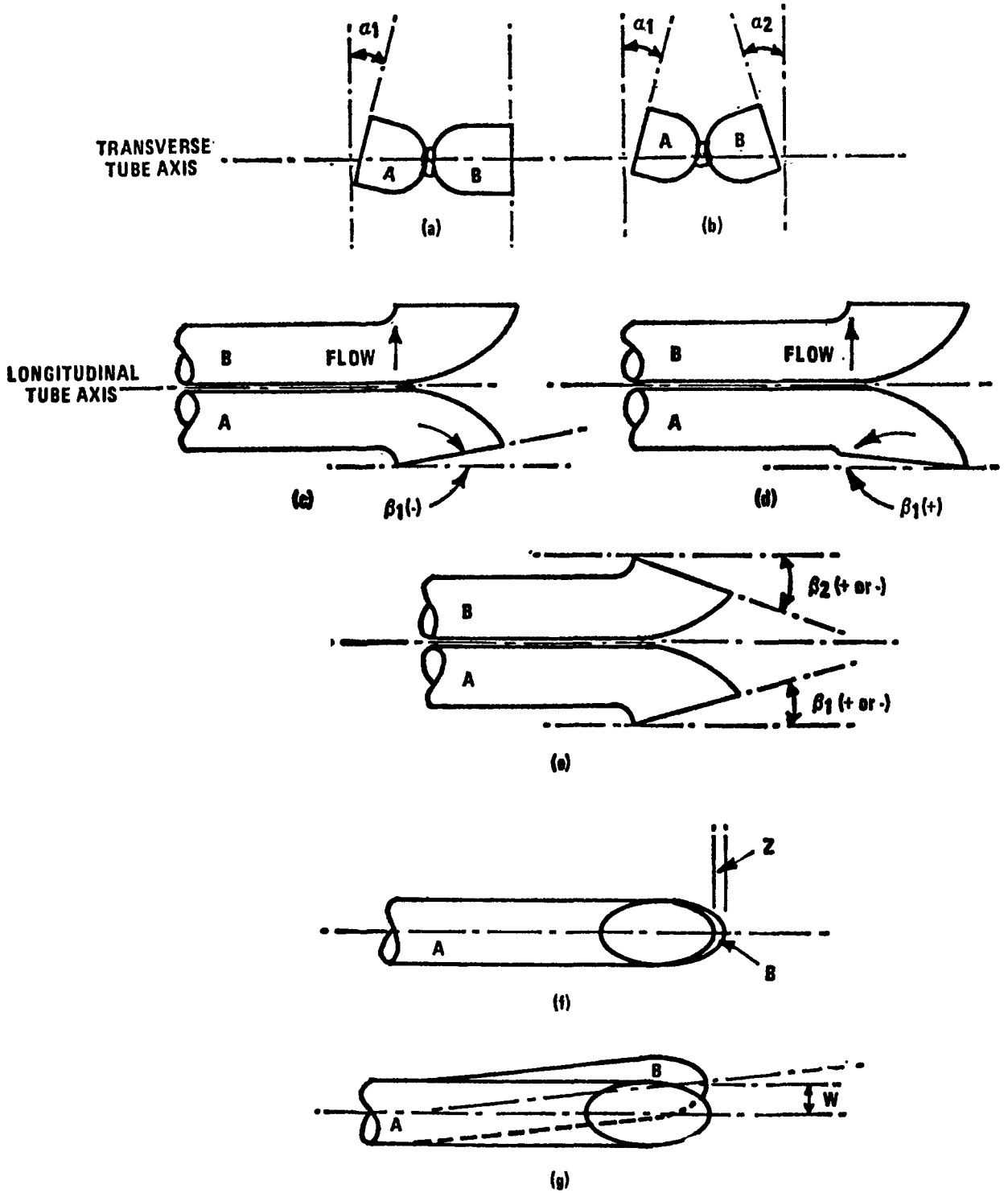


Figure 2-3. Types of face-opening misalignment that can result from field use or improper construction of Type S pitot tubes. These will not affect the baseline value of $\bar{C}p(s)$ so long as α_1 and $\alpha_2 < 10^o$, β_1 and $\beta_2 < 5^o$. $z < 0.32$ cm (1/8 in.) and $w <$ 0.08 cm (1/32 in.) (citation 11 in Section 6).

A standard pitot tube may be used instead of a Type S, provided that it meets the specifications of Sections 2.7 and 4.2; note, however, that the static and impact pressure holes of standard pitot tubes are susceptible to plugging in particulate-laden gas streams. Therefore, whenever a standard pitot tube is used to perform a traverse, adequate proof must be furnished that the openings of the pitot tube have not plugged up during the traverse period; this can be done by taking a velocity head (Δp) reading at the final traverse point, cleaning out the impact and static holes of the standard pitot tube by "back-purging" with pressurized air, and then taking another Δp reading. If the Δp readings made before and after the air purge are the same (±5 percent), the traverse is acceptable. Otherwise, reject the run. Note that if Δp at the final traverse point is unsuitably low, another point may be selected. If "back-purging" at regular intervals is part of the procedure, then comparative Δp readings shall be taken, as above, for the last two back purges at which suitably high Δp readings are observed.

2.2 Differential Pressure Gauge. An inclined manometer or equivalent device is used. Most sampling trains are equipped with a 10-in. (water column) inclined-vertical manometer, having 0.01-in. H_2O divisions on the 0- to 1-in. inclined scale, and 0.1-in. H_2O divisions on the 1- to 10-in. vertical scale. This type of manometer (or other gauge of equivalent sensitivity) is satisfactory for the measurement of Δp values as low as 1.3 mm (0.05 in.) H_2O. However, a differential pressure gauge of greater sensitivity shall be used (subject to the approval of the Administrator), if any of the following is found to be true: (1) the arithmetic average of all Δp readings at the traverse points in the stack is less than 1.3 mm (0.05 in.) H_2O; (2) for traverses of 12 or more points, more than 10 percent of the individual Δp readings are below 1.3 mm (0.05 in.) H_2O; (3) for traverses of fewer than 12 points, more than one Δp reading is below 1.3 mm (0.05 in.) H_2O. Citation 18 in Section 6 describes commercially available instrumentation for the measurement of low-range gas velocities.

As an alternative to criteria (1) through (3) above, the following calculation may be performed to determine the necessity of using a more sensitive differential pressure gauge.

$$T=\frac{\sum_{i=1}^{n}\sqrt{\Delta p_i+K}}{\sum_{i=1}^{n}\sqrt{\Delta p_i}}$$

where:

Δp_i = Individual velocity head reading at a traverse point, mm H_2O (in. H_2O).

n = Total number of traverse points.

K = 0.13 mm H_2O when metric units are used and 0.005 in H_2O when English units are used.

If T is greater than 1.05, the velocity head data are unacceptable and a more sensitive differential pressure gauge must be used.

NOTE.—If differential pressure gauges other than inclined manometers are used (e.g., magnehelic gauges), their calibration must be checked after each test series. To check the calibration of a differential pressure gauge, compare Δp readings of the gauge with those of a gauge-oil manometer at a minimum of three points, approximately representing the range of Δp values in the stack. If, at each point, the values of Δp as read by the differential pressure gauge and gauge-oil manometer agree to within 5 percent, the differential pressure gauge shall be considered to be in proper calibration. Otherwise, the test series shall either be voided, or procedures to adjust the measured Δp values and final results shall be used, subject to the approval of the Administrator.

2.3 Temperature Gauge. A thermocouple, liquid-filled bulb thermometer, bimetallic thermometer, mercury-in-glass thermometer, or other gauge capable of measuring temperature to within 1.5 percent of the minimum absolute stack temperature shall be used. The temperature gauge shall be attached to the pitot tube such that the sensor tip does not touch any metal; the gauge shall be in an interference-free arrangement with respect to the pitot tube face openings (see Figure 2-1 and also Figure 2-7 in Section 4). Alternate positions may be used if the pitot tube-temperature gauge system is calibrated according to the procedure of Section 4. Provided that a difference of not more than 1 percent in the average velocity measurement is introduced, the temperature gauge need not be attached to the pitot tube; this alternative is subject to the approval of the Administrator.

2.4 Pressure Probe and Gauge. A piezometer tube and mercury- or water-filled U-tube manometer capable of measuring stack pressure to within 2.5 mm (0.1 in.) Hg is used. The static tap of a standard type pitot tube or one leg of a Type X pitot tube with the face opening planes positioned parallel to the gas flow may also be used as the pressure probe.

2.5 Barometer. A mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg) may be used. In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and the sampling point shall be applied at a rate of minus 2.5 mm (0.1 in.) Hg per 30-meter (100 foot) elevation increase, or vice-versa for elevation decrease.

2.6 Gas Density Determination Equipment. Method 3 equipment, if needed (see Section 3.6), to determine the stack gas dry molecular weight, and Reference Method 4 or Method 5 equipment for moisture content determination; other methods may be used subject to approval of the Administrator.

2.7 Calibration Pitot Tube. When calibration of the Type S pitot tube is necessary (see Section 4), a standard pitot tube is used as a reference. The standard pitot tube shall, preferably, have a known coefficient, obtained either (1) directly from the National Bureau of Standards, Route 270, Quince Orchard Road, Gaithersburg, Maryland, or (2) by calibration against another standard pitot tube with an NBS-traceable coefficient. Alternatively, a standard pitot tube designed according to the criteria given in 2.7.1 through 2.7.5 below and illustrated in Figure 2-4 (see also Citations 7, 8, and 17 in Section 6) may be used. Pitot tubes designed according to these specifications will have baseline coefficients of about 0.99±0.01.

2.7.1 Hemispherical (shown in Figure 2-4), ellipsoidal, or conical tip.

2.7.2 A minimum of six diameters straight run (based upon D, the external diameter of the tube) between the tip and the static pressure holes.

2.7.3 A minimum of eight diameters straight run between the static pressure holes and the centerline of the external tube, following the 90 degree bend.

2.7.4 Static pressure holes of equal size (approximately 0.1 D), equally spaced in a piezometer ring configuration.

2.7.5 Ninety degree bend, with curved or mitered junction.

2.8 Differential Pressure Gauge for Type S Pitot Tube Calibration. An inclined manometer or equivalent is used. If the single-velocity calibration technique is employed (see Section 4.1.2.3), the calibration differential pressure gauge shall be readable to the nearest 0.13 mm H_2O (0.005 in. H_2O). For multivelocity calibrations, the gauge shall be readable to the nearest 0.13 mm H_2O (0.005 in H_2O) for Δp values between 1.3 and 25 mm H_2O (0.05 and 1.0 in. H_2O), and to the nearest 1.3 mm H_2O (0.05 in. H_2O) for Δp values above 25 mm H_2O (1.0 in. H_2O). A special, more sensitive gauge will be required to read Δp values below 1.3 mm H_2O [0.05 in. H_2O] (see Citation 18 in Section 6).

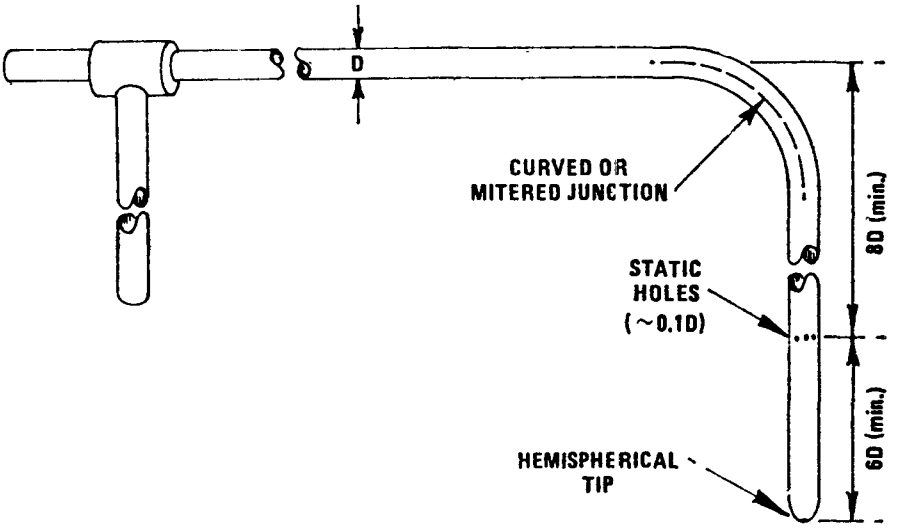


Figure 2-4. Standard pitot tube design specifications.

3. *Procedure*

3.1 Set up the apparatus as shown in Figure 2-1. Capillary tubing or surge tanks installed between the manometer and pitot tube may be used to dampen Δp fluctuations. It is recommended, but not required, that a pretest leak-check be conducted, as follows: (1) blow through the pitot impact opening until at least 7.6 cm (3 in.) H_2O velocity pressure registers on the manometer; then, close off the impact opening. The pressure shall remain stable for at least 15 seconds; (2) do the same for the static pressure side, except using suction to obtain the minimum of 7.6 cm (3 in.) H_2O. Other leak-check procedures, subject to the approval of the Administrator, may be used.

3.2 Level and zero the manometer. Because the manometer level and zero may drift due to vibrations and temperature changes, make periodic checks during the traverse. Record all necessary data as shown in the example data sheet (Figure 2-5).

3.3 Measure the velocity head and temperature at the traverse points specified by Method 1. Ensure that the proper differential pressure gauge is being used for the range of Δp values encountered (see Section 2.2). If it is necessary to change to a more sensitive gauge, do so, and remeasure the Δp and temperature readings at each traverse point. Conduct a post-test leak-check (mandatory), as described in Section 3.1 above, to validate the traverse run.

3.4 Measure the static pressure in the stack. One reading is usually adequate.

3.5 Determine the atmospheric pressure.

PLANT _____

DATE _____ RUN NO. _____

STACK DIAMETER OR DIMENSIONS, m(in.) _____

BAROMETRIC PRESSURE, mm Hg (in. Hg) _____

CROSS SECTIONAL AREA, $m^2(ft^2)$ _____

OPERATORS _____

PITOT TUBE I.D. NO. _____

AVG. COEFFICIENT, C_p = _____

LAST DATE CALIBRATED _____

SCHEMATIC OF STACK CROSS SECTION

Traverse Pt. No.	Vel. Hd., Δp mm (in.) H_2O	Stack Temperature		P_g mm Hg (in.Hg)	$\sqrt{\Delta p}$
		t_s, °C (°F)	T_s, °K (°R)		

3.6 Determine the stack gas dry molecular weight. For combustion processes or processes that emit essentially CO_2, O_2, CO, and N_2, use Method 3. For processes emitting essentially air, an analysis need not be conducted; use a dry molecular weight of 29.0. For other processes, other methods, subject to the approval of the Administrator, must be used.

3.7 Obtain the moisture content from Reference Method 4 (or equivalent) or from Method 5.

3.8 Determine the cross-sectional area of the stack or duct at the sampling location. Whenever possible, physically measure the stack dimensions rather than using blueprints.

4 *Calibration*

4.1 Type S Pitot Tube. Before its initial use, carefully examine the Type S pitot tube in top, side, and end views to verify that the face openings of the tube are aligned within the specifications illustrated in Figure 2-2 or 2-3. The pitot tube shall not be used if it fails to meet these alignment specifications.

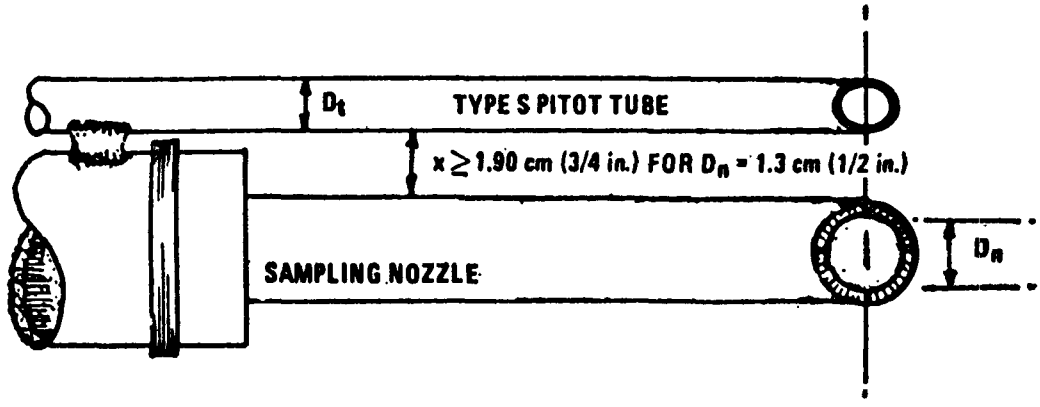
After verifying the face opening alignment, measure and record the following dimensions of the pitot tube: (a) the external tubing diameter (dimension D_t, Figure 2-2b); and (b) the base-to-opening plane distances (dimensions P_A and P_B, Figure 2-2b). If D_t is between 0.48 and 0.95 cm (3/16 and 3/8 in.) and if P_A and P_B are equal and between 1.05 and 1.50 D_t, there are two possible options: (1) the pitot tube may be calibrated according to the procedure outlined in Sections 4.1.2 through 4.1.5 below, or (2) a baseline (isolated tube) coefficient value of 0.84 may be assigned to the pitot tube. Note, however, that if the pitot tube is part of an assembly, calibration may still be required, despite knowledge of the baseline coefficient value (see Section 4.1.1).

If D_t, P_A, and P_B are outside the specified limits, the pitot tube must be calibrated as outlined in 4.1.2 through 4.1.5 below.

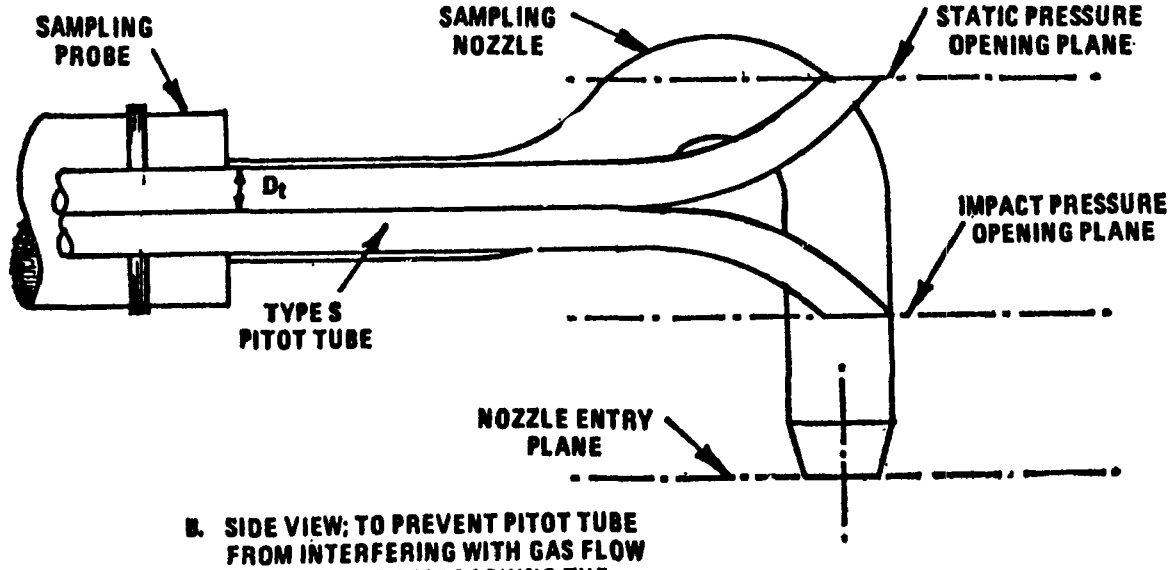
4.1.1 Type S Pitot Tube Assemblies. During sample and velocity traverses, the isolated Type S pitot tube is not always used; in many instances, the pitot tube is used in combination with other source-sampling components (thermocouple, sampling probe, nozzle) as part of an "assembly." The presence of other sampling components can sometimes affect the baseline value of the Type S pitot tube coefficient (Citation 9 in Section 6); therefore an assigned (or otherwise known) baseline coefficient value may or may not be valid for a given assembly. The baseline and assembly coefficient values will be identical only when the relative placement of the components in the assembly is such that aerodynamic interference effects are eliminated. Figures 2-6 through 2-8 illustrate interference-free component arrangements for Type S pitot tubes having external tubing diameters between 0.48 and 0.95 cm (3/16 and 3/8 in.). Type S pitot tube assemblies that fail to meet any or all of the specifications of Figures 2-6 through 2-8 shall be calibrated according to the procedure outlined in Sections 4.1.2 through 4.1.5 below, and prior to calibration, the values of the intercomponent spacings (pitot-nozzle, pitot-thermocouple, pitot-probe sheath) shall be measured and recorded.

NOTE.—Do not use any Type S pitot tube assembly which is constructed such that the impact pressure opening plane of the pitot tube is below the entry plane of the nozzle (see Figure 2-6b).

4.1.2 Calibration Setup. If the Type S pitot tube is to be calibrated, one leg of the tube shall be permanently marked A, and the other, B. Calibration shall be done in a flow system having the following essential design features:



A. BOTTOM VIEW; SHOWING MINIMUM PITOT-NOZZLE SEPARATION.



B. SIDE VIEW; TO PREVENT PITOT TUBE FROM INTERFERING WITH GAS FLOW STREAMLINES APPROACHING THE NOZZLE, THE IMPACT PRESSURE OPENING PLANE OF THE PITOT TUBE SHALL BE EVEN WITH OR ABOVE THE NOZZLE ENTRY PLANE.

Figure 2-6. Proper pitot tube - sampling nozzle configuration to prevent aerodynamic interference; buttonhook - type nozzle; centers of nozzle and pitot opening aligned; D_t between 0.48 and 0.95 cm (3/16 and 3/8 in.).

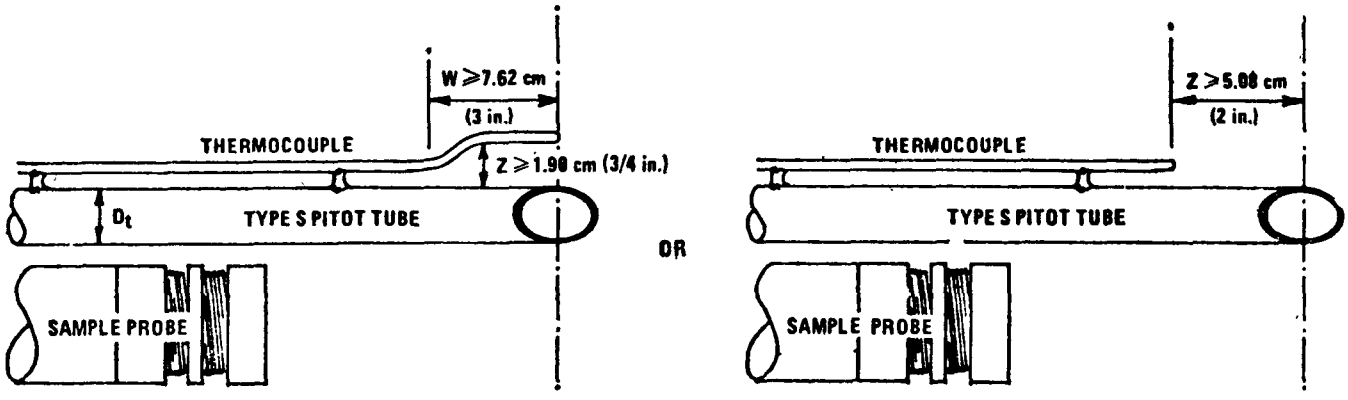


Figure 2-7. Proper thermocouple placement to prevent interference; D_t between 0.48 and 0.95 cm (3/16 and 3/8 in.).

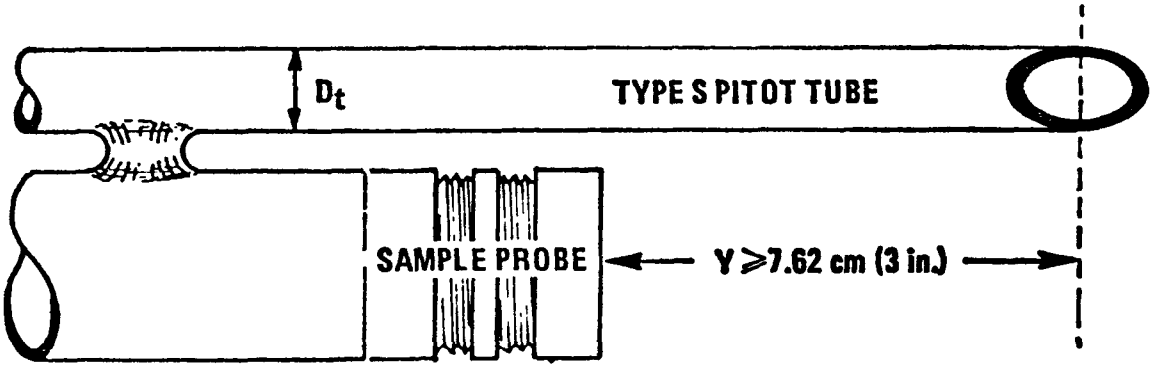


Figure 2-8. Minimum pitot-sample probe separation needed to prevent interference; D_t between 0.48 and 0.95 cm (3/16 and 3/8 in.).

4.1.2.1 The flowing gas stream must be confined to a duct of definite cross-sectional area, either circular or rectangular. For circular cross-sections, the minimum duct diameter shall be 30.5 cm (12 in.); for rectangular cross-sections, the width (shorter side) shall be at least 25.4 cm (10 in.).

4.1.2.2 The cross-sectional area of the calibration duct must be constant over a distance of 10 or more duct diameters. For a rectangular cross-section, use an equivalent diameter, calculated from the following equation, to determine the number of duct diameters:

$$D_e = \frac{2LW}{(L+W)}$$

Equation 2-1

where:
D_e = Equivalent diameter
L = Length
W = Width

To ensure the presence of stable, fully developed flow patterns at the calibration site, or "test section," the site must be located at least eight diameters downstream and two diameters upstream from the nearest disturbances.

NOTE.—The eight- and two-diameter criteria are not absolute; other test section locations may be used (subject to approval of the Administrator), provided that the flow at the test site is stable and demonstrably parallel to the duct axis.

4.1.2.3 The flow system shall have the capacity to generate a test-section velocity around 915 m/min (3,000 ft/min). This velocity must be constant with time to guarantee steady flow during calibration. Note that Type S pitot tube coefficients obtained by single-velocity calibration at 915 m/min (3,000 ft/min) will generally be valid to within ±3 percent for the measurement of velocities above 305 m/min (1,000 ft/min) and to within ±5 to 6 percent for the measurement of velocities between 180 and 305 m/min (600 and 1,000 ft/min). If a more precise correlation between C_p and velocity is desired, the flow system shall have the capacity to generate at least four distinct, time-invariant test-section velocities covering the velocity range from 180 to 1,525 m/min (600 to 5,000 ft/min), and calibration data shall be taken at regular velocity intervals over this range (see Citations 9 and 14 in Section 6 for details).

4.1.2.4 Two entry ports, one each for the standard and Type S pitot tubes, shall be cut in the test section; the standard pitot entry port shall be located slightly downstream of the Type S port, so that the standard and Type S impact openings will lie in the same cross-sectional plane during calibration. To facilitate alignment of the pitot tubes during calibration, it is advisable that the test section be constructed of plexiglas or some other transparent material.

4.1.3 Calibration Procedure. Note that this procedure is a general one and must not be used without first referring to the special considerations presented in Section 4.1.5. Note also that this procedure applies only to single-velocity calibration. To obtain calibration data for the A and B sides of the Type S pitot tube, proceed as follows:

4.1.3.1 Make sure that the manometer is properly filled and that the oil is free from contamination and is of the proper density. Inspect and leak-check all pitot lines; repair or replace if necessary.

4.1.3.2 Level and zero the manometer. Turn on the fan and allow the flow to stabilize. Seal the Type S entry port.

4.1.3.3 Ensure that the manometer is level and zeroed. Position the standard pitot tube at the calibration point (determined as outlined in Section 4.1.5.1), and align the tube so that its tip is pointed directly into the flow. Particular care should be taken in aligning the tube to avoid yaw and pitch angles. Make sure that the entry port surrounding the tube is properly sealed.

4.1.3.4 Read Δp_{std} and record its value in a data table similar to the one shown in Figure 2-9. Remove the standard pitot tube from the duct and disconnect it from the manometer. Seal the standard entry port.

4.1.3.5 Connect the Type S pitot tube to the manometer. Open the Type S entry port. Check the manometer level and zero. Insert and align the Type S pitot tube so that its A side impact opening is at the same point as was the standard pitot tube and is pointed directly into the flow. Make sure that the entry port surrounding the tube is properly sealed.

4.1.3.6 Read Δp_a and enter its value in the data table. Remove the Type S pitot tube from the duct and disconnect it from the manometer.

4.1.3.7 Repeat steps 4.1.3.3 through 4.1.3.6 above until three pairs of Δp readings have been obtained.

4.1.3.8 Repeat steps 4.1.3.3 through 4.1.3.7 above for the B side of the Type S pitot tube.

4.1.3.9 Perform calculations, as described in Section 4.1.4 below.

4.1.4 Calculations.

4.1.4.1 For each of the six pairs of Δp readings (i.e., three from side A and three from side B) obtained in Section 4.1.3 above, calculate the value of the Type S pitot tube coefficient as follows.

PITOT TUBE IDENTIFICATION NUMBER: _____ DATE: _____

CALIBRATED BY: _____

	"A" SIDE CALIBRATION			
RUN NO.	Δp_{std} cm H_2O (in. H_2O)	$\Delta p_{(s)}$ cm H_2O (in. H_2O)	$C_{p(s)}$	DEVIATION $C_{p(s)} - \bar{C}_p$(A)
1				
2				
3				
		$\bar{C}_p$ (SIDE A)		

	"B" SIDE CALIBRATION			
RUN NO.	Δp_{std} cm H_2O (in. H_2O)	$\Delta p_{(s)}$ cm H_2O (in. H_2O)	$C_{p(s)}$	DEVIATION $C_{p(s)} - \bar{C}_p$(B)
1				
2				
3				
		$\bar{C}_p$ (SIDE B)		

$$\text{AVERAGE DEVIATION} = \sigma\,(\text{A OR B}) = \frac{\sum_1^3 \left| C_{p(s)} - \bar{C}_p(\text{A OR B}) \right|}{3} \leftarrow \text{MUST BE} \leqslant 0.01$$

$$\left| \bar{C}_p\,(\text{SIDE A}) - \bar{C}_p\,(\text{SIDE B}) \right| \leftarrow \text{MUST BE} \leqslant 0.01$$

Figure 2-9. Pitot tube calibration data.

$$C_{p(s)} = C_{p(std)} \sqrt{\frac{\Delta p_{std}}{\Delta p_s}}$$

Equation 2-2

where:

$C_{p(s)}$ = Type S pilot tube coefficient

$C_{p(std)}$ = Standard pitot tube coefficient; use 0.99 if the coefficient is unknown and the tube is designed according to the criteria of Sections 2.7.1 to 2.7.5 of this method.

Δp_{std} = Velocity head measured by the standard pitot tube, cm H_2O (in. H_2O)

Δp_s = Velocity head measured by the Type S pitot tube, cm H_2O (in. H_2O)

4.1.4.2 Calculate $\bar{C}_p$ (side A), the mean A-side coefficient, and $\bar{C}_p$ (side B), the mean B-side coefficient; calculate the difference between these two average values.

4.1.4.3 Calculate the deviation of each of the three A-side values of $C_{p(s)}$ from $\bar{C}_p$ (side A), and the deviation of each B-side value of $C_{p(s)}$ from $\bar{C}_p$ (side B). Use the following equation:

$$\text{Deviation} = C_{p(s)} - \bar{C}_p(\text{A or B})$$

Equation 2-3

4.1.4.4 Calculate σ, the average deviation from the mean, for both the A and B sides of the pitot tube. Use the following equation:

$$\sigma\,(\text{side A or B}) = \frac{\sum_1^3 |C_{p(s)} - \bar{C}_p(A \text{ or } B)|}{3}$$

Equation 2-4

4.1.4.5 Use the Type S pitot tube only if the values of σ (side A) and σ (side B) are less than or equal to 0.01 and if the absolute value of the difference between $\bar{C}_p$ (A) and $\bar{C}_p$ (B) is 0.01 or less.

4.1.5 Special considerations.

4.1.5.1 Selection of calibration point.

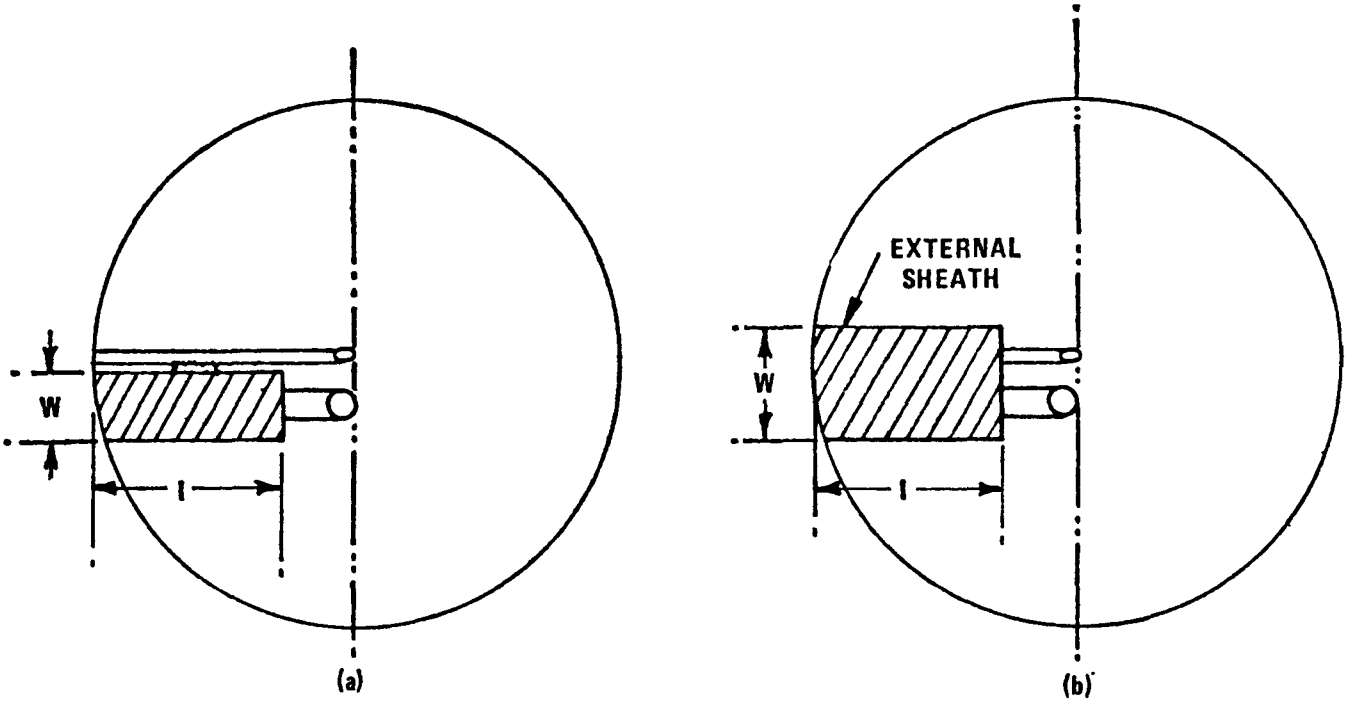
4.1.5.1.1 When an isolated Type S pitot tube is calibrated, select a calibration point at or near the center of the duct, and follow the procedures outlined in Sections 4.1.3 and 4.1.4 above. The Type S pitot coefficients so obtained, i.e., $\bar{C}_p$ (side A) and $\bar{C}_p$ (side B), will be valid, so long as either: (1) the isolated pitot tube is used; or (2) the pitot tube is used with other components (nozzle, thermocouple, sample probe) in an arrangement that is free from aerodynamic interference effects (see Figures 2-6 through 2-8).

4.1.5.1.2 For Type S pitot tube-thermocouple combinations (without sample probe), select a calibration point at or near the center of the duct, and follow the procedures outlined in Sections 4.1.3 and 4.1.4 above. The coefficients so obtained will be valid so long as the pitot tube-thermocouple combination is used by itself or with other components in an interference-free arrangement (Figures 2-6 and 2-8).

4.1.5.1.3 For assemblies with sample probes, the calibration point should be located at or near the center of the duct; however, insertion of a probe sheath into a small duct may cause significant cross-sectional area blockage and yield incorrect coefficient values (Citation 9 in Section 6). Therefore, to minimize the blockage effect, the calibration point may be a few inches off-center if necessary. The actual blockage effect will be negligible when the theoretical blockage, as determined by a projected-area model of the probe sheath, is 2 percent or less of the duct cross-sectional area for assemblies without external sheaths (Figure 2-10a), and 3 percent or less for assemblies with external sheaths (Figure 2-10b).

4.1.5.2 For those probe assemblies in which pitot tube-nozzle interference is a factor (i.e., those in which the pitot-nozzel separation distance fails to meet the specification illustrated in Figure 2-6a), the value of $C_{p(s)}$ depends upon the amount of free-space between the tube and nozzle, and therefore is a function of nozzle size. In these instances, separate calibrations shall be performed with each of the commonly used nozzle sizes in place. Note that the single-velocity calibration technique is acceptable for this purpose, even though the larger nozzle sizes (> 0.635 cm or ¼ in.) are not ordinarily used for isokinetic sampling at velocities around 915 m/min (3,000 ft/min), which is the calibration velocity; note also that it is not necessary to draw an isokinetic sample during calibration (see Citation 19 in Section 6).

4.1.5.3 For a probe assembly constructed such that its pitot tube is always used in the same orientation, only one side of the pitot tube need be calibrated (the side which will face the flow). The pitot tube must still meet the alignment specifications of Figure 2-2 or 2-3, however, and must have an average deviation (σ) value of 0.01 or less (see Section 4.1.4.4).



$$\text{ESTIMATED SHEATH BLOCKAGE (\%)} = \left[\frac{l \times W}{\text{DUCT AREA}}\right] \times 100$$

Figure 2-10. Projected-area models for typical pitot tube assemblies.

4.1.6 Field Use and Recalibration.

4.1.6.1 Field Use.

4.1.6.1.1 When a Type S pitot tube (isolated tube or assembly) is used in the field, the appropriate coefficient value (whether assigned or obtained by calibration) shall be used to perform velocity calculations. For calibrated Type S pitot tubes, the A side coefficient shall be used when the A side of the tube faces the flow, and the B side coefficient shall be used when the B side faces the flow; alternatively, the arithmetic average of the A and B side coefficient values may be used, irrespective of which side faces the flow.

4.1.6.1.2 When a probe assembly is used to sample a small duct (12 to 36 in. in diameter), the probe sheath sometimes blocks a significant part of the duct cross-section, causing a reduction in the effective value of $\overline{C_{p(s)}}$. Consult Citation 9 in Section 6 for details. Conventional pitot-sampling probe assemblies are not recommended for use in ducts having inside diameters smaller than 12 inches (Citation 16 in Section 6).

4.1.6.2 Recalibration.

4.1.6.2.1 Isolated Pitot Tubes. After each field use, the pitot tube shall be carefully reexamined in top, side, and end views. If the pitot face openings are still aligned within the specifications illustrated in Figure 2-2 or 2-3, it can be assumed that the baseline coefficient of the pitot tube has not changed. If, however, the tube has been damaged to the extent that it no longer meets the specifications of Figure 2-2 or 2-3, the damage shall either be repaired to restore proper alignment of the face openings or the tube shall be discarded.

4.1.6.2.2 Pitot Tube Assemblies. After each field use, check the face opening alignment of the pitot tube, as in Section 4.1.6.2.1; also, remeasure the intercomponent spacings of the assembly. If the intercomponent spacings have not changed and the face opening alignment is acceptable, it can be assumed that the coefficient of the assembly has not changed. If the face opening alignment is no longer within the specifications of Figures 2-2 or 2-3, either repair the damage or replace the pitot tube (calibrating the new assembly, if necessary). If the intercomponent spacings have changed, restore the original spacings or recalibrate the assembly.

4.2 Standard pitot tube (if applicable). If a standard pitot tube is used for the velocity traverse, the tube shall be constructed according to the criteria of Section 2.7 and shall be assigned a baseline coefficient value of 0.99. If the standard pitot tube is used as part of an assembly, the tube shall be in an interference-free arrangement (subject to the approval of the Administrator).

4.3 Temperature Gauges. After each field use, calibrate dial thermometers, liquid-filled bulb thermometers, thermocouple-potentiometer systems, and other gauges at a temperature within 10 percent of the average absolute stack temperature. For temperatures up to 405° C (761° F), use an ASTM mercury-in-glass reference thermometer, or equivalent, as a reference; alternatively, either a reference thermocouple and potentiometer (calibrated by NBS) or thermometric fixed points, e.g., ice bath and boiling water (corrected for barometric pressure) may be used. For temperatures above 405° C (761° F), use an NBS-calibrated reference thermocouple-potentiometer system or an alternate reference, subject to the approval of the Administrator.

If, during calibration, the absolute temperatures measured with the gauge being calibrated and the reference gauge agree within 1.5 percent, the temperature data taken in the field shall be considered valid. Otherwise, the pollutant emission test shall either be considered invalid or adjustments (if appropriate) of the test results shall be made, subject to the approval of the Administrator.

4.4 Barometer. Calibrate the barometer used against a mercury barometer.

5. *Calculations*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

5.1 Nomenclature.

A = Cross-sectional area of stack, m² (ft²).

B_{ws} = Water vapor in the gas stream (from Method 5 or Reference Method 4), proportion by volume.

C_p = Pitot tube coefficient, dimensionless.

K_p = Pitot tube constant,

$$34.97 \frac{\text{m}}{\text{sec}} \left[\frac{(g/g\text{-mole})(\text{mm Hg})}{(°\text{K})(\text{mm H}_2\text{O})}\right]^{1/2}$$

for the metric system and

$$85.49 \frac{\text{ft}}{\text{sec}} \left[\frac{(\text{lb/lb-mole})(\text{in. Hg})}{(°\text{R})(\text{in. H}_2\text{O})}\right]^{1/2}$$

for the English system.

M_d = Molecular weight of stack gas, dry basis (see Section 3.6) g/g-mole (lb/lb-mole).

M_s = Molecular weight of stack gas, wet basis, g/g-mole (lb/lb-mole).

$$= M_d(1-B_{ws}) + 18.0\,B_{ws} \qquad \text{Equation 2-5}$$

P_{bar} = Barometric pressure at measurement site, mm Hg (in. Hg).

P_g = Stack static pressure, mm Hg (in. Hg).

P_s = Absolute stack gas pressure, mm Hg (in. Hg).

$$= P_{bar} + P_g \qquad \text{Equation 2-6}$$

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

Q_{sd} = Dry volumetric stack gas flow rate corrected to standard conditions, dscm/hr (dscf/hr).

t_s = Stack temperature, °C (°F).

T_s = Absolute stack temperature, °K (°R).

$$= 273 + t_s \text{ for metric} \qquad \text{Equation 2-7}$$

$$= 460 + t_s \text{ for English} \qquad \text{Equation 2-8}$$

T_{std} = Standard absolute temperature, 293 °K (528° R).

v_s = Average stack gas velocity, m/sec (ft/sec).

Δp = Velocity head of stack gas, mm H_2O (in. H_2O).

3,600 = Conversion factor, sec/hr.

18.0 = Molecular weight of water, g/g-mole (lb-lb-mole).

5.2 Average stack gas velocity.

$$v_s = K_p C_p (\sqrt{\Delta p})_{avg} \sqrt{\frac{T_{s(avg)}}{P_s M_s}}$$

Equation 2-9

5.3 Average stack gas dry volumetric flow rate.

$$Q_{sd} = 3{,}600(1-B_{ws})\,v_s A \left(\frac{T_{std}}{T_{s(avg)}}\right)\left(\frac{P_s}{P_{std}}\right)$$

Equation 2-10

6. *Bibliography*

1. Mark, L. S. Mechanical Engineers' Handbook. New York, McGraw-Hill Book Co., Inc. 1951.

2. Perry, J. H. Chemical Engineers' Handbook. New York. McGraw-Hill Book Co., Inc. 1960.

3. Shigehara, R. T., W. F. Todd, and W. S. Smith. Significance of Errors in Stack Sampling Measurements. U.S. Environmental Protection Agency, Research Triangle Park, N.C. (Presented at the Annual Meeting of the Air Pollution Control Association, St. Louis, Mo., June 14-19, 1970.)

4. Standard Method for Sampling Stacks for Particulate Matter. In: 1971 Book of ASTM Standards, Part 23. Philadelphia, Pa. 1971. ASTM Designation D-2928-71.

5. Vennard, J. K. Elementary Fluid Mechanics. New York. John Wiley and Sons, Inc. 1947.

6. Fluid Meters—Their Theory and Application. American Society of Mechanical Engineers, New York, N.Y. 1959.

7. ASHRAE Handbook of Fundamentals, 1972. p. 208.

8. Annual Book of ASTM Standards, Part 26. 1974. p. 648.

9. Vollaro, R. F. Guidelines for Type S Pitot Tube Calibration. U.S. Environmental Protection Agency, Research Tiangle Park, N.C. (Presented at 1st Annual Meeting, Source Evaluation Society, Dayton, Ohio, September 18, 1975.)

10. Vollaro, R. F. A Type S Pitot Tube Calibration Study. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, N.C. July 1974.

11. Vollaro, R. F. The Effects of Impact Opening Misalignment on the Value of the Type S Pitot Tube Coefficient. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, N.C. October 1976.

12. Vollaro, R. F. Establishment of a Baseline Coefficient Value for Properly Constructed Type S Pitot Tubes. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, N.C. November 1976.

13. Vollaro, R. F. An Evaluation of Single-Velocity Calibration Techniques as a Means of Determining Type S Pitot Tube Coefficients. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, N.C. August 1975.

14. Vollaro, R. F. The Use of Type S Pitot Tubes for the Measurement of Low Velocities. U.S Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, N.C. November 1976.

15. Smith, Marvin L. Velocity Calibration of EPA Type Source Sampling Probe. United Technologies Corporation, Pratt and Whitney Aircraft Division, East Hartford, Conn. 1975.

16. Vollaro, R. F. Recommended Procedure for Sample Traverses in Ducts Smaller than 12 Inches in Diameter. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, N.C. November 1976.

17. Ower, E. and R. C. Pankhurst. The Measurement of Air Flow, 4th Ed., London, Pergamon Press. 1966.

18. Vollaro, R. F. A survey of Commercially Available Instrumentation for the Measurement of Low-Range Gas Velocities. U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, N.C. November 1976. (Unpublished Paper)

19. Gnyp, A. W., C. C. St. Pierre, D. S. Smith, D. Mozzon, and J. Steiner. An Experimental Investigation of the Effect of Pitot Tube-Sampling Probe Configurations on the Magnitude of the S Type Pitot Tube Coefficient for Commercially Available Source Sampling Probes. Prepared by the University of Windsor for the Ministry of the Environment, Toronto, Canada. February 1975.

METHOD 3—GAS ANALYSIS FOR CARBON DIOXIDE, OXYGEN, EXCESS AIR, AND DRY MOLECULAR WEIGHT

1. *Principle and Applicability*

1.1 Principle. A gas sample is extracted from a stack, by one of the following methods: (1) single-point, grab sampling; (2) single-point, integrated sampling; or (3) multi-point, integrated sampling. The gas sample is analyzed for percent carbon dioxide (CO_2), percent oxygen (O_2), and, if necessary, percent carbon monoxide (CO). If a dry molecular weight determination is to be made, either an Orsat or a Fyrite [1] analyzer may be used for the analysis; for excess air or emission rate correction factor determination, an Orsat analyzer must be used.

1.2 Applicability. This method is applicable for determining CO_2 and O_2 concentrations, excess air, and dry molecular weight of a sample from a gas stream of a fossil-fuel combustion process. The method may also be applicable to other processes where it has been determined that compounds other than CO_2, O_2, CO, and nitrogen (N_2) are not present in concentrations sufficient to affect the results.

Other methods, as well as modifications to the procedure described herein, are also applicable for some or all of the above determinations. Examples of specific methods and modifications include: (1) a multi-point sampling method using an Orsat analyzer to analyze individual grab samples obtained at each point; (2) a method using CO_2 or O_2 and stoichiometric calculations to determine dry molecular weight and excess air; (3) assigning a value of 30.0 for dry molecular weight, in lieu of actual measurements, for processes burning natural gas, coal, or oil. These methods and modifications may be used, but are subject to the approval of the Administrator.

2. *Apparatus*

As an alternative to the sampling apparatus and systems described herein, other sampling systems (e.g., liquid displacement) may be used provided such systems are capable of obtaining a representative sample and maintaining a constant sampling rate, and are otherwise capable of yielding acceptable results. Use of such systems is subject to the approval of the Administrator.

2.1 Grab Sampling (Figure 3-1).

2.1.1 Probe. The probe should be made of stainless steel or borosilicate glass tubing and should be equipped with an in-stack or out-stack filter to remove particulate matter (a plug of glass wool is satisfactory for this purpose). Any other material inert to O_2, CO_2, CO, and N_2 and resistant to temperature at sampling conditions may be used for the probe; examples of such material are aluminum, copper, quartz glass and Teflon.

2.1.2 Pump. A one-way squeeze bulb, or equivalent, is used to transport the gas sample to the analyzer.

2.2 Integrated Sampling (Figure 3-2).

2.2.1 Probe. A probe such as that described in Section 2.1.1 is suitable.

[1] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

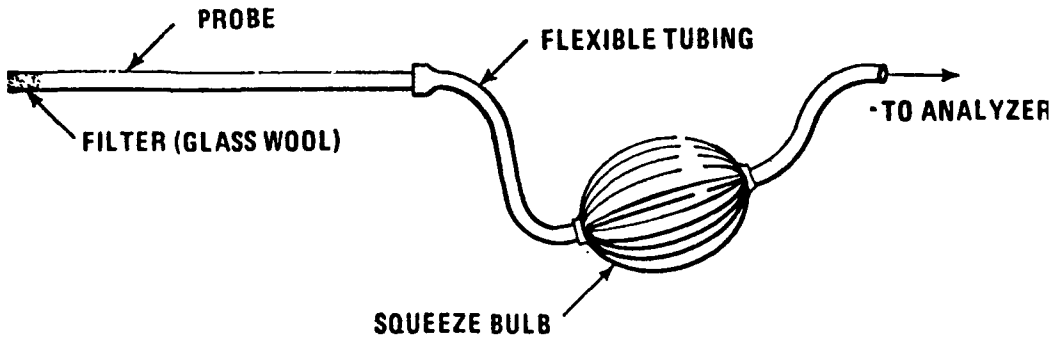


Figure 3-1. Grab-sampling train.

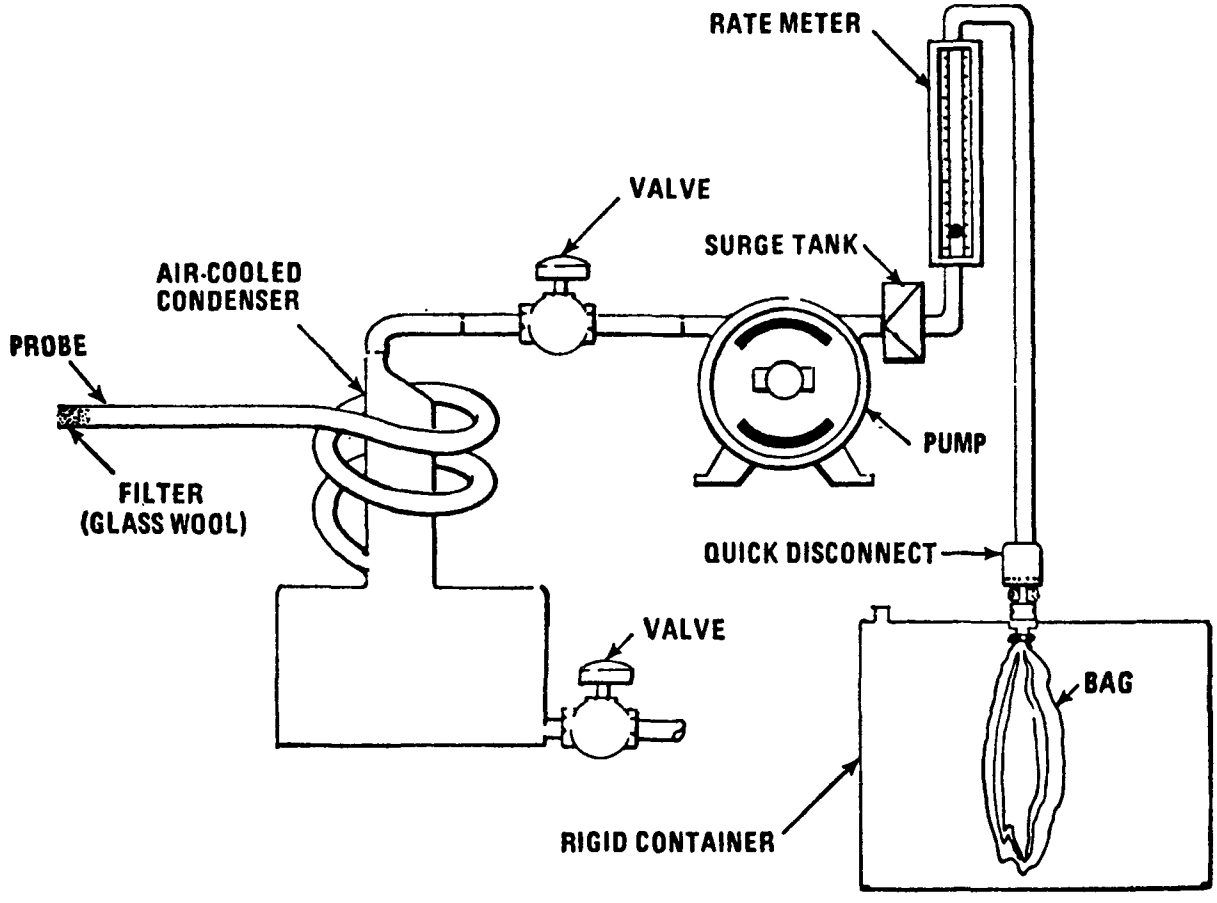


Figure 3-2. Integrated gas-sampling train.

2.2.2 Condenser. An air-cooled or water-cooled condenser, or other condenser that will not remove O_2, CO_2, CO, and N_2, may be used to remove excess moisture which would interfere with the operation of the pump and flow meter.

2.2.3 Valve. A needle valve is used to adjust sample gas flow rate.

2.2.4 Pump. A leak-free, diaphragm-type pump, or equivalent, is used to transport sample gas to the flexible bag. Install a small surge tank between the pump and rate meter to eliminate the pulsation effect of the diaphragm pump on the rotameter.

2.2.5 Rate Meter. The rotameter, or equivalent rate meter, used should be capable of measuring flow rate to within ±2 percent of the selected flow rate. A flow rate range of 500 to 1000 cm^3/min is suggested.

2.2.6 Flexible Bag. Any leak-free plastic (e.g., Tedlar, Mylar, Teflon) or plastic-coated aluminum (e.g., aluminized Mylar) bag, or equivalent, having a capacity consistent with the selected flow rate and time length of the test run, may be used. A capacity in the range of 85 to 90 liters is suggested.

To leak-check the bag, connect it to a water manometer and pressurize the bag to 5 to 10 cm H_2O (2 to 4 in. H_2O). Allow to stand for 10 minutes. Any displacement in the water manometer indicates a leak. An alternative leak-check method is to pressurize the bag to 5 to 10 cm H_2O (2 to 4 in. H_2O) and allow to stand overnight. A deflated bag indicates a leak.

2.2.7 Pressure Gauge. A water-filled U-tube manometer, or equivalent, of about 28 cm (12 in.) is used for the flexible bag leak-check.

2.2.8 Vacuum Gauge. A mercury manometer, or equivalent, of at least 760 mm Hg (30 in. Hg) is used for the sampling train leak-check.

2.3 Analysis. For Orsat and Fyrite analyzer maintenance and operation procedures, follow the instructions recommended by the manufacturer, unless otherwise specified herein.

2.3.1 Dry Molecular Weight Determination. An Orsat analyzer or Fyrite type combustion gas analyzer may be used.

2.3.2 Emission Rate Correction Factor or Excess Air Determination. An Orsat analyzer must be used. For low CO_2 (less than 4.0 percent) or high O_2 (greater than 15.0 percent) concentrations, the measuring burette of the Orsat must have at least 0.1 percent subdivisions.

3 *Dry Molecular Weight Determination*

Any of the three sampling and analytical procedures described below may be used for determining the dry molecular weight.

3.1 Single-Point, Grab Sampling and Analytical Procedure.

3.1.1 The sampling point in the duct shall either be at the centroid of the cross section or at a point no closer to the walls than 1.00 m (3.3 ft), unless otherwise specified by the Administrator.

3.1.2 Set up the equipment as shown in Figure 3-1, making sure all connections ahead of the analyzer are tight and leak-free. If an Orsat analyzer is used, it is recommended that the analyzer be leaked-checked by following the procedure in Section 5; however, the leak-check is optional.

3.1.3 Place the probe in the stack, with the tip of the probe positioned at the sampling point; purge the sampling line. Draw a sample into the analyzer and immediately analyze it for percent CO_2 and percent O_2. Determine the percentage of the gas that is N_2 and CO by subtracting the sum of the percent CO_2 and percent O_2 from 100 percent. Calculate the dry molecular weight as indicated in Section 6.3.

3.1.4 Repeat the sampling, analysis, and calculation procedures, until the dry molecular weights of any three grab samples differ from their mean by no more than 0.3 g/g-mole (0.3 lb/lb-mole). Average these three molecular weights, and report the results to the nearest 0.1 g/g-mole (lb/lb-mole).

3.2 Single-Point, Integrated Sampling and Analytical Procedure.

3.2.1 The sampling point in the duct shall be located as specified in Section 3.1.1.

3.2.2 Leak-check (optional) the flexible bag as in Section 2.2.6. Set up the equipment as shown in Figure 3-2. Just prior to sampling, leak-check (optional) the train by placing a vacuum gauge at the condenser inlet, pulling a vacuum of at least 250 mm Hg (10 in. Hg), plugging the outlet at the quick disconnect, and then turning off the pump. The vacuum should remain stable for at least 0.5 minute. Evacuate the flexible bag. Connect the probe and place it in the stack, with the tip of the probe positioned at the sampling point; purge the sampling line. Next, connect the bag and make sure that all connections are tight and leak free.

3.2.3 Sample at a constant rate. The sampling run should be simultaneous with, and for the same total length of time as, the pollutant emission rate determination. Collection of at least 30 liters (1.00 ft^3) of sample gas is recommended, however, smaller volumes may be collected, if desired.

3.2.4 Obtain one integrated flue gas sample during each pollutant emission rate determination. Within 8 hours after the sample is taken, analyze it for percent CO_2 and percent O_2 using either an Orsat analyzer or a Fyrite-type combustion gas analyzer. If an Orsat analyzer is used, it is recommended that the Orsat leak-check described in Section 5 be performed before this determination; however, the check is optional. Determine the percentage of the gas that is N_2 and CO by subtracting the sum of the percent CO_2 and percent O_2 from 100 percent. Calculate the dry molecular weight as indicated in Section 6.3.

3.2.5 Repeat the analysis and calculation procedures until the individual dry molecular weights for any three analyses differ from their mean by no more than 0.3 g/g-mole (0.3 lb/lb-mole). Average these three molecular weights, and report the results to the nearest 0.1 g/g-mole (0.1 lb/lb-mole).

3.3 Multi-Point, Integrated Sampling and Analytical Procedure.

3.3.1 *Unless otherwise specified by the Administrator*, a minimum of eight traverse points shall be used for circular stacks having diameters less then 0.61 m (24 in.), a minimum of nine shall be used for rectangular stacks having equivalent diameters less than 0.61 m (24 in.), and a minimum of twelve traverse points shall be used for all other cases. The traverse points shall be located according to Method 1. The use of fewer points is subject to approval of the Administrator.

3.3.2 Follow the procedures outlined in Sections 3.2.2 through 3.2.5, except for the following: traverse all sampling points and sample at each point for an equal length of time. Record sampling data as shown in Figure 3-3.

4. *Emission Rate Correction Factor or Excess Air Determination*

NOTE.—A Fyrite type combustion gas analyzer is not acceptable for excess air or emission rate correction factor determination, unless approved by the Administrator. If both percent CO_2 and percent O_2 are measured, the analytical results of any of the three procedures given below may also be used for calculating the dry molecular weight.

Each of the three procedures below shall be used only when specified in an applicable subpart of the standards. The use of these procedures for other purposes must have specific prior approval of the Administrator.

4.1 Single-Point, Grab Sampling and Analytical Procedure.

4.1.1 The sampling point in the duct shall either be at the centroid of the cross-section or at a point no closer to the walls than 1.00 m (3.3 ft), unless otherwise specified by the Administrator.

4.1.2 Set up the equipment as shown in Figure 3-1, making sure all connections ahead of the analyzer are tight and leak-free. Leak-check the Orsat analyzer according to the procedure described in Section 5. This leak-check is mandatory.

TIME	TRAVERSE PT.	Q 1pm	% DEV.[a]
	AVERAGE		

[a] $\%\ DEV = \left(\frac{Q - Q_{avg}}{Q_{avg}}\right) 100$ (MUST BE ≤10%)

Figure 3-3. Sampling rate data.

4.1.3 Place the probe in the stack, with the tip of the probe positioned at the sampling point; purge the sampling line. Draw a sample into the analyzer. For emission rate correction factor determination, immediately analyze the sample, as outlined in Sections 4.1.4 and 4.1.5, for percent CO_2 or percent O_2. If excess air is desired, proceed as follows: (1) immediately analyze the sample, as in Sections 4.1.4 and 4.1.5, for percent CO_2, O_2, and CO; (2) determine the percentage of the gas that is N_2 by subtracting the sum of the percent CO_2, percent O_2, and percent CO from 100 percent; and (3) calculate percent excess air as outlined in Section 6.2.

4.1.4 To ensure complete absorption of the CO_2, O_2, or if applicable, CO, make repeated passes through each absorbing solution until two consecutive readings are the same. Several passes (three or four) should be made between readings. (*If constant readings cannot* be obtained after three consecutive readings, replace the absorbing solution.)

4.1.5 After the analysis is completed, leak-check (mandatory) the Orsat analyzer once again, as described in Section 5. For the results of the analysis to be valid, the Orsat analyzer must pass this leak test before and after the analysis. NOTE.—Since this single-point, grab sampling and analytical *procedure is normally* conducted in conjunction with a single-point, grab sampling and analytical procedure for a pollutant, only one analysis is ordinarily conducted. Therefore, great care must be taken to obtain a valid sample and analysis. Although in most cases only CO_2 or O_2 is required, it is recommended that both CO_2 and O_2 be measured, and that Citation 5 in the Bibliography be used to validate the analytical data.

4.2 Single-Point, Integrated Sampling and Analytical Procedure.

4.2.1 The sampling point in the duct shall be located as specified in Section 4.1.1.

4.2.2 Leak-check (mandatory) the flexible bag as in Section 2.2.6. Set up the equipment as shown in Figure 3-2. Just prior to sampling, leak-check (mandatory) the train by placing a vacuum gauge at the condenser inlet, pulling a vacuum of at least 250 mm Hg (10 in. Hg), plugging the outlet at the quick disconnect, and then turning off the pump. The vacuum shall remain stable for at least 0.5 minute. Evacuate the flexible bag. Connect the probe and place it in the stack, with the tip of the probe positioned at the sampling point; purge the sampling line. Next, connect the bag and make sure that all connections are tight and leak free.

4.2.3 Sample at a constant rate, or as specified by the Administrator. The sampling run must be simultaneous with, and for the same total length of time as, the pollutant emission rate determination. Collect at least 30 liters (1.00 ft^3) of sample gas. Smaller volumes may be collected, subject to approval of the Administrator.

4.2.4 Obtain one integrated flue gas sample during each pollutant emission rate determination. *For emission* rate correction factor determination, analyze the sample within 4 hours after it is taken for percent CO_2 or percent O_2 (as outlined in Sections 4.2.5 through 4.2.7). The Orsat analyzer must be leak-checked (see Section 5) before the analysis. If excess air is desired, proceed as follows: (1) within 4 hours after the sample is taken, analyze it (as in Sections 4.2.5 through 4.2.7) for percent CO_2, O_2, and CO; (2) determine the percentage of the gas that is N_2 by subtracting the sum of the percent CO_2, percent O_2, and percent CO from 100 percent; (3) calculate percent excess air, as outlined in Section 6.2.

4.2.5 To ensure complete absorption of the CO_2, O_2, or if applicable, CO, make repeated passes through each absorbing solution until two consecutive readings are the same. Several passes (three or four) should be made between readings. (If constant readings cannot be obtained after three consecutive readings, replace the absorbing solution.)

4.2.6 Repeat the analysis until the following criteria are met:

4.2.6.1 For percent CO_2, repeat the analytical procedure until the results of any three analyses differ by no more than (a) 0.3 percent by volume when CO_2 is greater than 4.0 percent or (b) 0.2 percent by volume when CO_2 is less than or equal to 4.0 percent. Average the three acceptable values of percent CO_2 and report the results to the nearest 0.1 percent.

4.2.6.2 For percent O_2, repeat the analytical procedure until the results of any three analyses differ by no more

than (a) 0.3 percent by volume when O_2 is less than 15.0 percent or (b) 0.2 percent by volume when O_2 is greater than 15.0 percent. Average the three acceptable values of percent O_2 and report the results to the nearest 0.1 percent.

4.2.6.3 For percent CO, repeat the analytical procedure until the results of any three analyses differ by no more than 0.3 percent. Average the three acceptable values of percent CO and report the results to the nearest 0.1 percent.

4.2.7 After the analysis is completed, leak-check (mandatory) the Orsat analyzer once again, as described in Section 5. For the results of the analysis to be valid, the Orsat analyzer must pass this leak test before and after the analysis. Note: Although in most instances only CO_2 or O_2 is required, it is recommended that both CO_2 and O_2 be measured, and that Citation 5 in the Bibliography be used to validate the analytical data.

4.3 Multi-Point, Integrated Sampling and Analytical Procedure.

4.3.1 Both the minimum number of sampling points and the sampling point location shall be as specified in Section 3.3.1 of this method. The use of fewer points than specified is subject to the approval of the Administrator.

4.3.2 Follow the procedures outlined in Sections 4.2.2 through 4.2.7, except for the following: Traverse all sampling points and sample at each point for an equal length of time. Record sampling data as shown in Figure 3-3.

5. Leak-Check Procedure for Orsat Analyzers

Moving an Orsat analyzer frequently causes it to leak. Therefore, an Orsat analyzer should be thoroughly leak-checked on site before the flue gas sample is introduced into it. The procedure for leak-checking an Orsat analyzer is:

5.1.1 Bring the liquid level in each pipette up to the reference mark on the capillary tubing and then close the pipette stopcock.

5.1.2 Raise the leveling bulb sufficiently to bring the confining liquid meniscus onto the graduated portion of the burette and then close the manifold stopcock.

5.1.3 Record the meniscus position.

5.1.4 Observe the meniscus in the burette and the liquid level in the pipette for movement over the next 4 minutes.

5.1.5 For the Orsat analyzer to pass the leak-check, two conditions must be met.

5.1.5.1 The liquid level in each pipette must not fall below the bottom of the capillary tubing during this 4-minute interval.

5.1.5.2 The meniscus in the burette must not change by more than 0.2 ml during this 4-minute interval.

5.1.6 If the analyzer fails the leak-check procedure, all rubber connections and stopcocks should be checked until the cause of the leak is identified. Leaking stopcocks must be disassembled, cleaned, and regreased. Leaking rubber connections must be replaced. After the analyzer is reassembled, the leak-check procedure must be repeated.

6. Calculations

6.1 Nomenclature.

M_d = Dry molecular weight, g/g-mole (lb/lb-mole).
%EA = Percent excess air.
$\%CO_2$ = Percent CO_2 by volume (dry basis).
$\%O_2$ = Percent O_2 by volume (dry basis).
%CO = Percent CO by volume (dry basis).
$\%N_2$ = Percent N_2 by volume (dry basis).
0.264 = Ratio of O_2 to N_2 in air, v/v.
0.280 = Molecular weight of N_2 or CO, divided by 100.
0.320 = Molecular weight of O_2 divided by 100.
0.440 = Molecular weight of CO_2 divided by 100.

6.2 Percent Excess Air Calculate the percent excess air (if applicable), by substituting the appropriate values of percent O_2, CO, and N_2 (obtained from Section 4.1.3 or 4.2.4) into Equation 3-1

$$\%EA = \left[\frac{\%O_2 - 0.5\%CO}{0.264\%N_2 - (\%O_2 - 0.5\%CO)}\right] 100$$

Equation 3-1

NOTE.—The equation above assumes that ambient air is used as the source of O_2 and that the fuel does not contain appreciable amounts of N_2 (as do coke oven or blast furnace gases). For those cases when appreciable amounts of N_2 are present (coal, oil, and natural gas do not contain appreciable amounts of N_2) or when oxygen enrichment is used, alternate methods, subject to approval of the Administrator, are required.

6.3 Dry Molecular Weight Use Equation 3-2 to calculate the dry molecular weight of the stack gas

$$M_d = 0.440(\%CO_2) + 0.320(\%O_2) + 0.280(\%N_2 + \%CO)$$

Equation 3-2

NOTE.—The above equation does not consider argon in air (about 0.9 percent, molecular weight of 37.7). A negative error of about 0.4 percent is introduced. The tester may opt to include argon in the analysis using procedures subject to approval of the Administrator.

7. Bibliography

1. Altshuller, A. P. Storage of Gases and Vapors in Plastic Bags. International Journal of Air and Water Pollution. 6:75-81. 1963.

2. Conner, William D. and J. S. Nader. Air Sampling Plastic Bags. Journal of the American Industrial Hygiene Association. 25:291-297. 1964.

3. Burrell Manual for Gas Analysts, Seventh edition. Burrell Corporation, 2223 Fifth Avenue, Pittsburgh, Pa. 15219. 1951.

4. Mitchell, W. J. and M. R. Midgett. Field Reliability of the Orsat Analyzer. Journal of Air Pollution Control Association 26:491-495. May 1976.

5. Shigehara, R. T., R. M. Neulicht, and W. S. Smith. Validating Orsat Analysis Data from Fossil Fuel-Fired Units. Stack Sampling News. 4(2):21-26. August, 1976.

METHOD 4—DETERMINATION OF MOISTURE CONTENT IN STACK GASES

1. Principle and Applicability

1.1 Principle. A gas sample is extracted at a constant rate from the source, moisture is removed from the sample stream and determined either volumetrically or gravimetrically.

1.2 Applicability. This method is applicable for determining the moisture content of stack gas.

Two procedures are given. The first is a reference method, for accurate determinations of moisture content (such as are needed to calculate emission data). The second is an approximation method, which provides estimates of percent moisture to aid in setting isokinetic sampling rates prior to a pollutant emission measurement run. The approximation method described herein is only a suggested approach, alternative means for approximating the moisture content, e.g., drying tubes, wet bulb-dry bulb techniques, condensation techniques, stoichiometric calculations, previous experience, etc., are also acceptable.

The reference method is often conducted simultaneously with a pollutant emission measurement run, when it is, calculation of percent isokinetic, pollutant emission rate, etc., for the run shall be based upon the results of the reference method or its equivalent; these calculations shall not be based upon the results of the approximation method, unless the approximation method is shown, to the satisfaction of the Administrator, U.S. Environmental Protection Agency, to be capable of yielding results within 1 percent H_2O of the reference method.

NOTE.—The reference method may yield questionable results when applied to saturated gas streams or to streams that contain water droplets. Therefore, when these conditions exist or are suspected, a second determination of the moisture content shall be made simultaneously with the reference method, as follows: Assume that the gas stream is saturated. Attach a temperature sensor [capable of measuring to ±1° C (2° F)] to the reference method probe. Measure the stack gas temperature at each traverse point (see Section 2.2.1) during the reference method traverse, calculate the average stack gas temperature. Next, determine the moisture percentage, either by: (1) using a psychrometric chart and making appropriate corrections if stack pressure is different from that of the chart, or (2) using saturation vapor pressure tables. In cases where the psychrometric chart or the saturation vapor pressure tables are not applicable (based on evaluation of the process), alternate methods, subject to the approval of the Administrator, shall be used.

2. Reference Method

The procedure described in Method 5 for determining moisture content is acceptable as a reference method.

2.1 Apparatus. A schematic of the sampling train used in this reference method is shown in Figure 4-1. All components shall be maintained and calibrated according to the procedure outlined in Method 5.

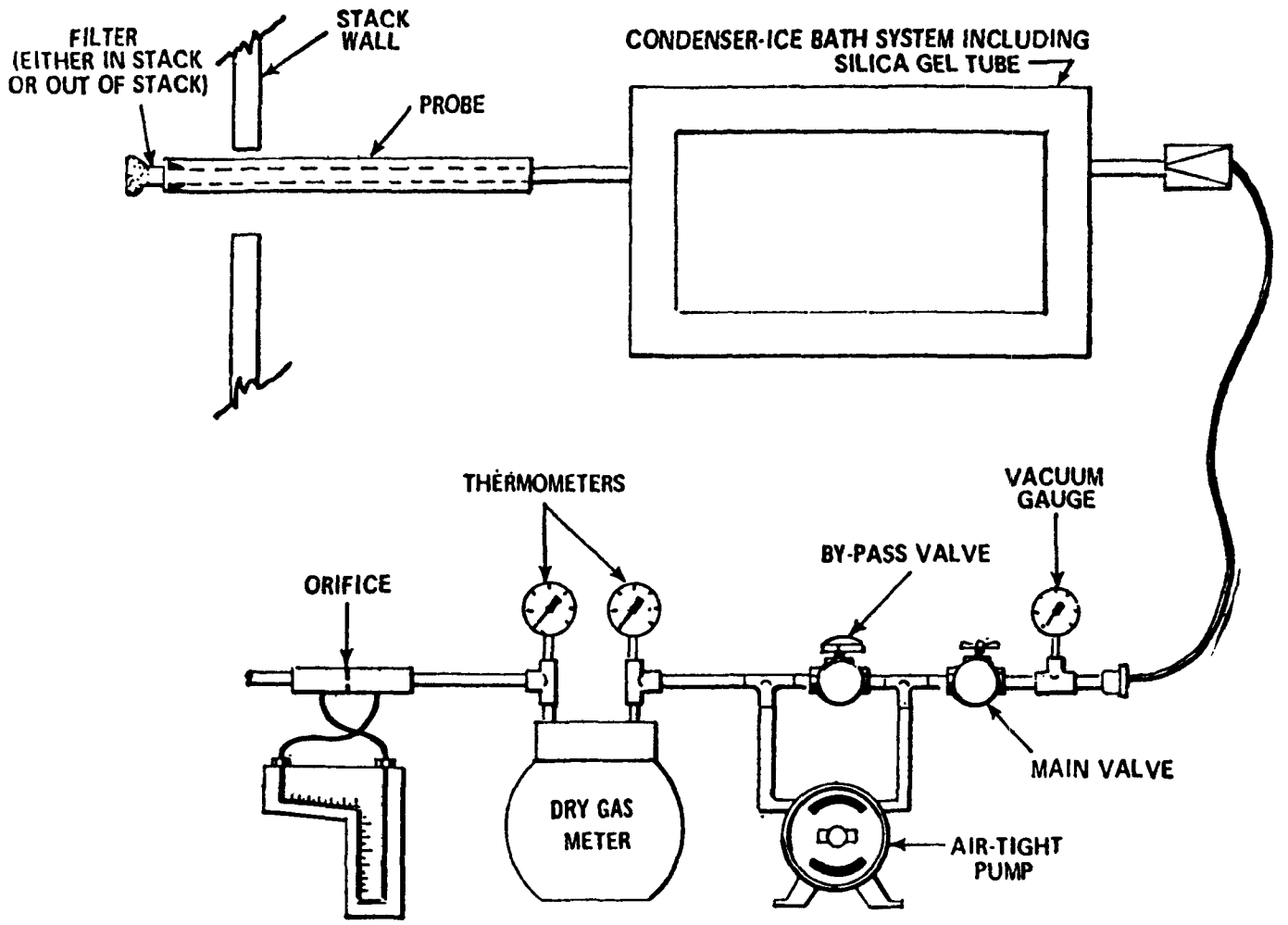


Figure 4-1. Moisture sampling train-reference method.

2.1.1 Probe. The probe is constructed of stainless steel or glass tubing, sufficiently heated to prevent water condensation, and is equipped with a filter, either in-stack (e.g., a plug of glass wool inserted into the end of the probe) or heated out-stack (e.g., as described in Method 5), to remove particulate matter.

When stack conditions permit, other metals or plastic tubing may be used for the probe, subject to the approval of the Administrator.

2.1.2 Condenser. The condenser consists of four impingers connected in series with ground glass, leak-free fittings or any similarly leak-free non-contaminating fittings. The first, third, and fourth impingers shall be of the Greenburg-Smith design, modified by replacing the tip with a 1.3 centimeter (½ inch) ID glass tube extending to about 1.3 cm (½ in.) from the bottom of the flask. The second impinger shall be of the Greenburg-Smith design with the standard tip. Modifications (e.g., using flexible connections between the impingers, using materials other than glass, or using flexible vacuum lines to connect the filter holder to the condenser) may be used, subject to the approval of the Administrator.

The first two impingers shall contain known volumes of water, the third shall be empty, and the fourth shall contain a known weight of 6- to 16-mesh indicating type silica gel, or equivalent desiccant. If the silica gel has been previously used, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. A thermometer, capable of measuring temperature to within 1° C (2° F), shall be placed at the outlet of the fourth impinger, for monitoring purposes.

Alternatively, any system may be used (subject to the approval of the Administrator) that cools the sample gas stream and allows measurement of both the water that has been condensed and the moisture leaving the condenser, each to within 1 ml or 1 g. Acceptable means are to measure the condensed water, either gravimetrically or volumetrically, and to measure the moisture leaving the condenser by: (1) monitoring the temperature and pressure at the exit of the condenser and using Dalton's law of partial pressures, or (2) passing the sample gas stream through a tared silica gel (or equivalent desiccant) trap, with exit gases kept below 20° C (68° F), and determining the weight gain.

If means other than silica gel are used to determine the amount of moisture leaving the condenser, it is recommended that silica gel (or equivalent) still be used between the condenser system and pump, to prevent moisture condensation in the pump and metering devices and to avoid the need to make corrections for moisture in the metered volume.

2.1.3 Cooling System. An ice bath container and crushed ice (or equivalent) are used to aid in condensing moisture.

2.1.4 Metering System. This system includes a vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3° C (5.4° F), dry gas meter capable of measuring volume to within 2 percent, and related equipment as shown in Figure 4-1. Other metering systems, capable of maintaining a constant sampling rate and determining sample gas volume, may be used, subject to the approval of the Administrator.

2.1.5 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg) may be used. In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and the sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.

2.1.6 Graduated Cylinder and/or Balance. These items are used to measure condensed water and moisture caught in the silica gel to within 1 ml or 0.5 g. Graduated cylinders shall have subdivisions no greater than 2 ml. Most laboratory balances are capable of weighing to the nearest 0.5 g or less. These balances are suitable for use here.

2.2 Procedure. The following procedure is written for a condenser system (such as the impinger system described in Section 2.1.2) incorporating volumetric analysis to measure the condensed moisture, and silica gel and gravimetric analysis to measure the moisture leaving the condenser.

2.2.1 Unless otherwise specified by the Administrator, a minimum of eight traverse points shall be used for circular stacks having diameters less than 0.61 m (24 in.), a minimum of nine points shall be used for rectangular stacks having equivalent diameters less than 0.61 m (24 in.), and a minimum of twelve travers points shall be used in all other cases. The traverse points shall be located according to Method 1. The use of fewer points is subject to the approval of the Administrator. Select a suitable probe and probe length such that all traverse points can be sampled. Consider sampling from opposite sides of the stack (four total sampling ports) for large stacks, to permit use of shorter probe lengths. Mark the probe with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point. Place known volumes of water in the first two impingers. Weigh and record the weight of the silica gel to the nearest 0.5 g, and transfer the silica gel to the fourth impinger; alternatively, the silica gel may first be transferred to the impinger, and the weight of the silica gel plus impinger recorded.

2.2.2 Select a total sampling time such that a minimum total gas volume of 0.60 scm (21 scf) will be collected, at a rate no greater than 0.021 m³/min (0.75 cfm). When both moisture content and pollutant emission rate are to be determined, the moisture determination shall be simultaneous with, and for the same total length of time as, the pollutant emission rate run, unless otherwise specified in an applicable subpart of the standards.

2.2.3 Set up the sampling train as shown in Figure 4-1. Turn on the probe heater and (if applicable) the filter heating system to temperatures of about 120° C (248° F), to prevent water condensation ahead of the condenser; allow time for the temperatures to stabilize. Place crushed ice in the ice bath container. It is recommended, but not required, that a leak check be done, as follows: Disconnect the probe from the first impinger or

(if applicable) from the filter holder. Plug the inlet to the first impinger (or filter holder) and pull a 380 mm (15 in.) Hg vacuum; a lower vacuum may be used, provided that it is not exceeded during the test. A leakage rate in excess of 4 percent of the average sampling rate or 0.00057 m³/min (0.02 cfm), whichever is less, is unacceptable. Following the leak check, reconnect the probe to the sampling train.

2.2.4 During the sampling run, maintain a sampling rate within 10 percent of constant rate, or as specified by the Administrator. For each run, record the data required on the example data sheet shown in Figure 4-2. Be sure to record the dry gas meter reading at the beginning and end of each sampling time increment and whenever sampling is halted. Take other appropriate readings at each sample point, at least once during each time increment.

2.2.5 To begin sampling, position the probe tip at the first traverse point. Immediately start the pump and adjust the flow to the desired rate. Traverse the cross section, sampling at each traverse point for an equal length of time. Add more ice and, if necessary, salt to maintain a temperature of less than 20° C (68° F) at the silica gel outlet.

2.2.6 After collecting the sample, disconnect the probe from the filter holder (or from the first impinger) and conduct a leak check (mandatory) as described in Section 2.2.3. Record the leak rate. If the leakage rate exceeds the allowable rate, the tester shall either reject the test results or shall correct the sample volume as in Section 6.3 of Method 5. Next, measure the volume of the moisture condensed to the nearest ml. Determine the increase in weight of the silica gel (or silica gel plus impinger) to the nearest 0.5 g. Record this information (see example data sheet, Figure 4-3) and calculate the moisture percentage, as described in 2.3 below.

2.3 Calculations. Carry out the following calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

PLANT_____

LOCATION_____

OPERATOR_____

DATE_____

RUN NO._____

AMBIENT TEMPERATURE_____

BAROMETRIC PRESSURE_____

PROBE LENGTH m(ft)_____

SCHEMATIC OF STACK CROSS SECTION

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	STACK TEMPERATURE °C (°F)	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER (ΔH), mm(in.) H_2O	METER READING GAS SAMPLE VOLUME m^3 (ft^3)	ΔV_m m^3 (ft^3)	GAS SAMPLE TEMPERATURE AT DRY GAS METER		TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °C (°F)
						INLET ($T_{m_{in}}$), °C (°F)	OUTLET ($T_{m_{out}}$), °C (°F)	
TOTAL						Avg.	Avg.	
AVERAGE						Avg.		

Figure 4-2. Field moisture determination-reference method.

	IMPINGER VOLUME, ml	SILICA GEL WEIGHT, g
FINAL		
INITIAL		
DIFFERENCE		

Figure 4-3. Analytical data reference method.

2.3.1 Nomenclature.

B_{ws} = Proportion of water vapor, by volume, in the gas stream.

M_w = Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).

P_m = Absolute pressure (for this method, same as barometric pressure) at the dry gas meter, mm Hg (in. Hg).

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R = Ideal gas constant, 0.06236 (mm Hg) (m^3)/(g-mole) (°K) for metric units and 21.85 (in. Hg) (ft^3)/(lb-mole) (°R) for English units.

T_m = Absolute temperature at meter, °K (°R).

T_{std} = Standard absolute temperature, 293° K (528° R).

V_m = Dry gas volume measured by dry gas meter, dcm (dcf).

ΔV_m = Incremental dry gas volume measured by dry gas meter at each traverse point, dcm (dcf).

$V_{m(std)}$ = Dry gas volume measured by the dry gas meter, corrected to standard conditions, dscm (dscf).

$V_{wc(std)}$ = Volume of water vapor condensed corrected to standard conditions, scm (scf).

$V_{wg(std)}$ = Volume of water vapor collected in silica gel corrected to standard conditions, scm (scf).

V_f = Final volume of condenser water, ml.

V_i = Initial volume, if any, of condenser water, ml.

W_f = Final weight of silica gel or silica gel plus impinger, g.

W_i = Initial weight of silica gel or silica gel plus impinger, g.

Y = Dry gas meter calibration factor.

ρ_w = Density of water, 0.9982 g/ml (0.002201 lb/ml).

2.3.2 Volume of water vapor condensed.

$$V_{wc(std)} = \frac{(V_f - V_i)\rho_w R T_{std}}{P_{std} M_w} = K_1 (V_f - V_i)$$

Equation 4-1

where:

K_1 = 0.001333 m^3/ml for metric units
= 0.04707 ft^3/ml for English units

2.3.3 Volume of water vapor collected in silica gel.

$$V_{wg(std)} = \frac{(W_f - W_i) R T_{std}}{P_{std} M_w} = K_2 (W_f - W_i)$$

Equation 4-2

where:

K_2 = 0.001335 m^3/g for metric units
= 0.04715 ft^3/g for English units

2.3.4 Sample gas volume.

$$V_{m(std)} = V_m Y \frac{(P_m)(T_{std})}{(P_{std})(T_m)} = K_3 Y \frac{V_m P_m}{T_m}$$

Equation 4-3

where

K_3 = 0.3858 °K/mm Hg for metric units
= 17.64 °R/in. Hg for English units

NOTE.—If the post-test leak rate (Section 2.2.6) exceeds the allowable rate, correct the value of V_m in Equation 4-3, as described in Section 6.3 of Method 5.

2.3.5 Moisture Content

$$B_{ws} = \frac{V_{wc(std)} + V_{wg(std)}}{V_{wc(std)} + V_{wg(std)} + V_{m(std)}}$$

Equation 4-4

NOTE.—In saturated or moisture droplet-laden gas streams, two calculations of the moisture content of the stack gas shall be made, one using a value based upon the saturated conditions (see Section 1.2), and another based upon the results of the impinger analysis. The lower of these two values of B_{ws} shall be considered correct.

2.3.6 Verification of constant sampling rate. For each time increment, determine the ΔV_m. Calculate the average. If the value for any time increment differs from the average by more than 10 percent, reject the results and repeat the run.

3 *Approximation Method*

The approximation method described below is presented only as a suggested method (see Section 1.2).

3.1 Apparatus.

3.1.1 Probe. Stainless steel or glass tubing, sufficiently heated to prevent water condensation and equipped with a filter (either in-stack or heated out-stack) to remove particulate matter. A plug of glass wool, inserted into the end of the probe, is a satisfactory filter.

3.1.2 Impingers. Two midget impingers, each with 30 ml capacity, or equivalent.

3.1.3 Ice Bath. Container and ice, to aid in condensing moisture in impingers.

3.1.4 Drying Tube. Tube packed with new or regenerated 6- to 16-mesh indicating-type silica gel (or equivalent desiccant), to dry the sample gas and to protect the meter and pump.

3.1.5 Valve. Needle valve, to regulate the sample gas flow rate.

3.1.6 Pump. Leak-free, diaphragm type, or equivalent, to pull the gas sample through the train.

3.1.7 Volume meter. Dry gas meter, sufficiently accurate to measure the sample volume within 2%, and calibrated over the range of flow rates and conditions actually encountered during sampling.

3.1.8 Rate Meter. Rotameter, to measure the flow range from 0 to 3 l pm (0 to 0.11 cfm).

3.1.9 Graduated Cylinder. 25 ml.

3.1.10 Barometer. Mercury, aneroid, or other barometer, as described in Section 2.1.5 above.

3.1.11 Vacuum Gauge. At least 760 mm Hg (30 in. Hg) gauge, to be used for the sampling leak check.

3.2 Procedure.

3.2.1 Place exactly 5 ml distilled water in each impinger. Assemble the apparatus without the probe as shown in Figure 4-4. Leak check the train by placing a vacuum gauge at the inlet to the first impinger and drawing a vacuum of at least 250 mm Hg (10 in. Hg), plugging the outlet of the rotameter, and then turning off the pump. The vacuum shall remain constant for at least one minute. Carefully release the vacuum gauge before unplugging the rotameter end.

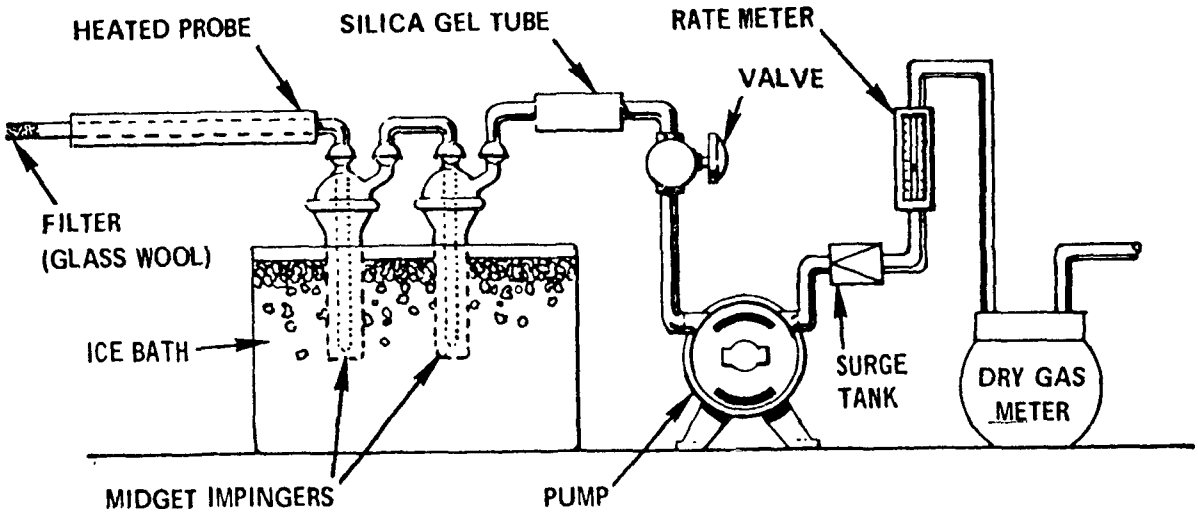


Figure 4-4. Moisture-sampling train - approximation method.

LOCATION _____ COMMENTS

TEST _____

DATE _____

OPERATOR _____

BAROMETRIC PRESSURE _____

CLOCK TIME	GAS VOLUME THROUGH METER, (Vm), m^3 (ft^3)	RATE METER SETTING $m^3/min.$ ($ft^3/min.$)	METER TEMPERATURE, °C (°F)

Figure 4-5. Field moisture determination - approximation method.

3.2.2 Connect the probe, insert it into the stack, and sample at a constant rate of 2 lpm (0.071 cfm). Continue sampling until the dry gas meter registers about 30 liters (1.1 ft³) or until visible liquid droplets are carried over from the first impinger to the second. Record temperature, pressure, and dry gas meter readings as required by Figure 4–5.

3.2.3 After collecting the sample, combine the contents of the two impingers and measure the volume to the nearest 0.5 ml.

3.3 Calculations. The calculation method presented is designed to estimate the moisture in the stack gas; therefore, other data, which are only necessary for accurate moisture determinations, are not collected. The following equations adequately estimate the moisture content, for the purpose of determining isokinetic sampling rate settings.

3.3.1 Nomenclature.

B_{ws} = Approximate proportion, by volume, of water vapor in the gas stream leaving the second impinger, 0.025.

B_{wa} = Water vapor in the gas stream, proportion by volume.

M_w = Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole)

P_m = Absolute pressure (for this method, same as barometric pressure) at the dry gas meter.

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R = Ideal gas constant, 0.06236 (mm Hg) (m³)/(g-mole) (°K) for metric units and 21.85 (in. Hg) (ft³)/lb-mole) (°R) for English units.

T_m = Absolute temperature at meter, °K (°R)

T_{std} = Standard absolute temperature, 293° K (528° R)

V_f = Final volume of impinger contents, ml.

V_i = Initial volume of impinger contents, ml.

V_m = Dry gas volume measured by dry gas meter, dcm (dcf).

$V_{m(std)}$ = Dry gas volume measured by dry gas meter, corrected to standard conditions, dscm (dscf).

$V_{wc(std)}$ = Volume of water vapor condensed, corrected to standard conditions, scm (scf).

ρ_w = Density of water, 0.9982 g/ml (0.002201 lb/ml).

3.3.2 Volume of water vapor collected.

$$V_{wc} = \frac{(V_f - V_i)\rho_w R T_{std}}{P_{std} M_w} = K_1 (V_f - V_i)$$

Equation 4–5

where:

K_1 = 0.001333 m³/ml for metric units
= 0.04707 ft³/ml for English units.

3.3.3 Gas volume.

$$V_{m(std)} = V_m \left(\frac{P_m}{P_{std}}\right)\left(\frac{T_{std}}{T_m}\right) = K_2 \frac{V_m P_m}{T_m}$$

Equation 4–6

where:

K_2 = 0.3858 °K/mm Hg for metric units
= 17.64 °R/in. Hg for English units

3.3.4 Approximate moisture content.

$$B_{ws} = \frac{V_{wc}}{V_{wc} + V_{m(std)}} + B_{wm} = \frac{V_{wc}}{V_{wc} + V_{m(std)}} + (0.025)$$

Equation 4–7

4. *Calibration*

4.1 For the reference method, calibrate equipment as specified in the following sections of Method 5: Section 5.3 (metering system); Section 5.5 (temperature gauges); and Section 5.7 (barometer). The recommended leak check of the metering system (Section 5.6 of Method 5) also applies to the reference method. For the approximation method, use the procedures outlined in Section 5.1.1 of Method 6 to calibrate the metering system, and the procedure of Method 5, Section 5.7 to calibrate the barometer.

5. *Bibliography*

1. Air Pollution Engineering Manual (Second Edition). Danielson, J. A. (ed.). U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, N.C. Publication No. AP–40. 1973.

2. Devorkin, Howard, et al. Air Pollution Source Testing Manual. Air Pollution Control District, Los Angeles, Calif. November, 1963.

3. Methods for Determination of Velocity, Volume, Dust and Mist Content of Gases. Western Precipitation Division of Joy Manufacturing Co., Los Angeles, Calif. Bulletin WP–50. 1968.

METHOD 5—DETERMINATION OF PARTICULATE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and Applicability*

1.1 Principle. Particulate matter is withdrawn isokinetically from the source and collected on a glass fiber filter maintained at a temperature in the range of 120±14° C (248±25° F) or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator, U.S. Environmental Protection Agency, for a particular application. The particulate mass, which includes any material that condenses at or above the filtration temperature, is determined gravimetrically after removal of uncombined water.

1.2 Applicability. This method is applicable for the determination of particulate emissions from stationary sources.

2. *Apparatus*

2.1 Sampling Train. A schematic of the sampling train used in this method is shown in Figure 5–1. Complete construction details are given in APTD–0581 (Citation 2 in Section 7); commercial models of this train are also available. For changes from APTD–0581 and for allowable modifications of the train shown in Figure 5–1, see the following subsections.

The operating and maintenance procedures for the sampling train are described in APTD–0576 (Citation 3 in Section 7). Since correct usage is important in obtaining valid results, all users should read APTD–0576 and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein. The sampling train consists of the following components:

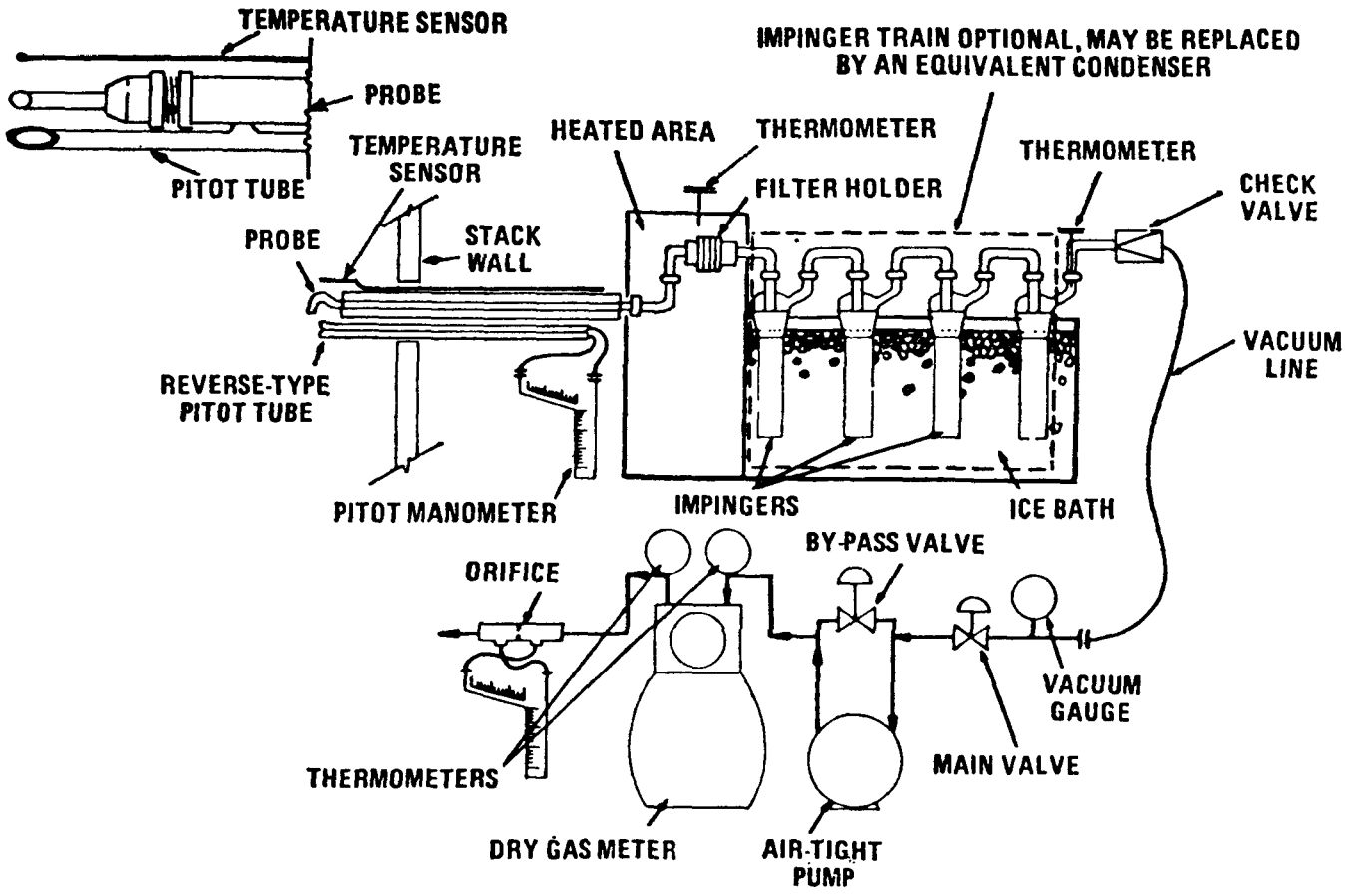


Figure 5-1. Particulate-sampling train.

2.1.1 Probe Nozzle. Stainless steel (316) or glass with sharp, tapered leading edge. The angle of taper shall be ≤30° and the taper shall be on the outside to preserve a constant internal diameter. The probe nozzle shall be of the button-hook or elbow design, unless otherwise specified by the Administrator. If made of stainless steel, the nozzle shall be constructed from seamless tubing; other materials of construction may be used, subject to the approval of the Administrator.

A range of nozzle sizes suitable for isokinetic sampling should be available, e.g., 0.32 to 1.27 cm (⅛ to ½ in.)—or larger if higher volume sampling trains are used—inside diameter (ID) nozzles in increments of 0.16 cm (1/16 in.). Each nozzle shall be calibrated according to the procedures outlined in Section 5.

2.1.2 Probe Liner. Borosilicate or quartz glass tubing with a heating system capable of maintaining a gas temperature at the exit end during sampling of 120±14° C (248±25° F), or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator for a particular application. (The tester may opt to operate the equipment at a temperature lower than that specified.) Since the actual temperature at the outlet of the probe is not usually monitored during sampling, probes constructed according to APTD-0581 and utilizing the calibration curves of APTD-0576 (or calibrated according to the procedure outlined in APTD-0576) will be considered acceptable.

Either borosilicate or quartz glass probe liners may be used for stack temperatures up to about 480° C (900° F); quartz liners shall be used for temperatures between 480 and 900° C (900 and 1,650° F). Both types of liners may be used at higher temperatures than specified for short periods of time, subject to the approval of the Administrator. The softening temperature for borosilicate is 820° C (1,508° F), and for quartz it is 1,500° C (2,732° F).

Whenever practical, every effort should be made to use borosilicate or quartz glass probe liners. Alternatively, metal liners (e.g., 316 stainless steel, Incoloy 825,[2] or other corrosion resistant metals) made of seamless tubing may be used, subject to the approval of the Administrator.

2.1.3 Pitot Tube. Type S, as described in Section 2.1 of Method 2, or other device approved by the Administrator. The pitot tube shall be attached to the probe (as shown in Figure 5-1) to allow constant monitoring of the stack gas velocity. The impact (high pressure) opening plane of the pitot tube shall be even with or above the nozzle entry plane (see Method 2, Figure 2-6b) during sampling. The Type S pitot tube assembly shall have a known coefficient, determined as outlined in Section 4 of Method 2.

2.1.4 Differential Pressure Gauge. Inclined manometer or equivalent device (two), as described in Section 2.2 of Method 2. One manometer shall be used for velocity head (Δp) readings, and the other, for orifice differential pressure readings.

2.1.5 Filter Holder. Borosilicate glass, with a glass frit filter support and a silicone rubber gasket. Other materials of construction (e.g., stainless steel, Teflon, Viton) may be used, subject to approval of the Administrator. The holder design shall provide a positive seal against leakage from the outside or around the filter. The holder shall be attached immediately at the outlet of the probe (or cyclone, if used).

2.1.6 Filter Heating System. Any heating system capable of maintaining a temperature around the filter holder during sampling of 120±14° C (248±25° F), or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator for a particular application. Alternatively, the tester may opt to operate the equipment at a temperature lower than that specified. A temperature gauge capable of measuring temperature to within 3° C (5.4° F) shall be installed so that the temperature around the filter holder can be regulated and monitored during sampling. Heating systems other than the one shown in APTD-0581 may be used.

2.1.7 Condenser. The following system shall be used to determine the stack gas moisture content: Four impingers connected in series with leak-free ground glass fittings or any similar leak-free non-contaminating fittings. The first, third, and fourth impingers shall be of the Greenburg-Smith design, modified by replacing the tip with 1.3 cm (½ in.) ID glass tube extending to about 1.3 cm (½ in.) from the bottom of the flask. The second impinger shall be of the Greenburg-Smith design with the standard tip. Modifications (e.g., using flexible connections between the impingers, using materials other than glass, or using flexible vacuum lines to connect the filter holder to the condenser) may be used, subject to the approval of the Administrator. The first and second impingers shall contain known quantities of water (Section 4.1.3), the third shall be empty, and the fourth shall contain a known weight of silica gel, or equivalent desiccant. A thermometer, capable of measuring temperature to within 1° C (2° F) shall be placed at the outlet of the fourth impinger for monitoring purposes.

Alternatively, any system that cools the sample gas stream and allows measurement of the water condensed and moisture leaving the condenser, each to within 1 ml or 1 g may be used, subject to the approval of the Administrator. Acceptable means are to measure the condensed water either gravimetrically or volumetrically and to measure the moisture leaving the condenser by: (1) monitoring the temperature and pressure at the exit of the condenser and using Dalton's law of partial pressures; or (2) passing the sample gas stream through a tared silica gel (or equivalent desiccant) trap with exit gases kept below 20° C (68° F) and determining the weight gain.

If means other than silica gel are used to determine the amount of moisture leaving the condenser, it is recommended that silica gel (or equivalent) still be used between the condenser system and pump to prevent moisture condensation in the pump and metering devices and to avoid the need to make corrections for moisture in the metered volume.

NOTE.—If a determination of the particulate matter collected in the impingers is desired in addition to moisture content, the impinger system described above shall be used, without modification. Individual States or control agencies requiring this information shall be contacted as to the sample recovery and analysis of the impinger contents.

2.1.8 Metering System. Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3° C (5.4° F), dry gas meter capable of measuring volume to within 2 percent, and related equipment, as shown in Figure 5-1. Other metering systems capable of maintaining sampling rates within 10 percent of isokinetic and of determining sample volumes to within 2 percent may be used, subject to the approval of the Administrator. When the metering system is used in conjunction with a pitot tube, the system shall enable checks of isokinetic rates.

Sampling trains utilizing metering systems designed for higher flow rates than that described in APTD-0581 or APTD-0576 may be used provided that the specifications of this method are met.

2.1.9 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is

[2] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.

2.1.10 Gas Density Determination Equipment. Temperature sensor and pressure gauge, as described in Sections 2.3 and 2.4 of Method 2, and gas analyzer, if necessary, as described in Method 3. The temperature sensor shall, preferably, be permanently attached to the pitot tube or sampling probe in a fixed configuration, such that the tip of the sensor extends beyond the leading edge of the probe sheath and does not touch any metal. Alternatively, the sensor may be attached just prior to use in the field. Note, however, that if the temperature sensor is attached in the field, the sensor must be placed in an interference-free arrangement with respect to the Type S pitot tube openings (see Method 2, Figure 2-7). As a second alternative, if a difference of not more than 1 percent in the average velocity measurement is to be introduced, the temperature gauge need not be attached to the probe or pitot tube. (This alternative is subject to the approval of the Administrator.)

2.2 Sample Recovery. The following items are needed.

2.2.1 Probe-Liner and Probe-Nozzle Brushes. Nylon bristle brushes with stainless steel wire handles. The probe brush shall have extensions (at least as long as the probe) of stainless steel, Nylon, Teflon, or similarly inert material. The brushes shall be properly sized and shaped to brush out the probe liner and nozzle.

2.2.2 Wash Bottles—Two. Glass wash bottles are recommended; polyethylene wash bottles may be used at the option of the tester. It is recommended that acetone not be stored in polyethylene bottles for longer than a month.

2.2.3 Glass Sample Storage Containers. Chemically resistant, borosilicate glass bottles, for acetone washes, 500 ml or 1000 ml. Screw cap liners shall either be rubber-backed Teflon or shall be constructed so as to be leak-free and resistant to chemical attack by acetone. (Narrow mouth glass bottles have been found to be less prone to leakage.) Alternatively, polyethylene bottles may be used.

2.2.4 Petri Dishes. For filter samples, glass or polyethylene, unless otherwise specified by the Administrator.

2.2.5 Graduated Cylinder and/or Balance. To measure condensed water to within 1 ml or 1 g. Graduated cylinders shall have subdivisions no greater than 2 ml. Most laboratory balances are capable of weighing to the nearest 0.5 g or less. Any of these balances is suitable for use here and in Section 2.3.4.

2.2.6 Plastic Storage Containers. Air-tight containers to store silica gel.

2.2.7 Funnel and Rubber Policeman. To aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.

2.2.8 Funnel. Glass or polyethlene, to aid in sample recovery.

2.3 Analysis. For analysis, the following equipment is needed.

2.3.1 Glass Weighing Dishes.

2.3.2 Desiccator.

2.3.3 Analytical Balance. To measure to within 0.1 mg.

2.3.4 Balance. To measure to within 0.5 g.

2.3.5 Beakers. 250 ml.

2.3.6 Hygrometer. To measure the relative humidity of the laboratory environment.

2.3.7 Temperature Gauge. To measure the temperature of the laboratory environment.

3. Reagents

3.1 Sampling. The reagents used in sampling are as follows:

3.1.1 Filters. Glass fiber filters, without organic binder, exhibiting at least 99.95 percent efficiency (≤0.05 percent penetration) on 0.3-micron dioctyl phthalate smoke particles. The filter efficiency test shall be conducted in accordance with ASTM standard method D 2986-71. Test data from the supplier's quality control program are sufficient for this purpose.

3.1.2 Silica Gel. Indicating type, 6 to 16 mesh. If previously used, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to the approval of the Administrator.

3.1.3 Water. When analysis of the material caught in the impingers is required, distilled water shall be used. Run blanks prior to field use to eliminate a high blank on test samples.

3.1.4 Crushed Ice.

3.1.5 Stopcock Grease. Acetone-insoluble, heat-stable silicone grease. This is not necessary if screw-on connectors with Teflon sleeves, or similar, are used. Alternatively, other types of stopcock grease may be used, subject to the approval of the Administrator.

3.2 Sample Recovery. Acetone—reagent grade, ≤0.001 percent residue, in glass bottles—is required. Acetone from metal containers generally has a high residue blank and should not be used. Sometimes, suppliers transfer acetone to glass bottles from metal containers; thus, acetone blanks shall be run prior to field use and only acetone with low blank values (≤0.001 percent) shall be used. In no case shall a blank value of greater than 0.001 percent of the weight of acetone used be subtracted from the sample weight.

3.3 Analysis. Two reagents are required for the analysis:

3.3.1 Acetone. Same as 3.2.

3.3.2 Desiccant. Anhydrous calcium sulfate, indicating type. Alternatively, other types of desiccants may be used, subject to the approval of the Administrator.

4. Procedure

4.1 Sampling. The complexity of this method is such that, in order to obtain reliable results, testers should be trained and experienced with the test procedures.

4.1.1 Pretest Preparation. All the components shall be maintained and calibrated according to the procedure described in APTD-0576, unless otherwise specified herein.

Weigh several 200 to 300 g portions of silica gel in air-tight containers to the nearest 0.5 g. Record the total weight of the silica gel plus container, on each container. As an alternative, the silica gel need not be preweighed, but may be weighed directly in its impinger or sampling holder just prior to train assembly.

Check filters visually against light for irregularities and flaws or pinhole leaks. Label filters of the proper diameter on the back side near the edge using numbering machine ink. As an alternative, label the shipping containers (glass or plastic petri dishes) and keep the filters in these containers at all times except during sampling and weighing.

Desiccate the filters at 20±5.6° C (68±10° F) and ambient pressure for at least 24 hours and weigh at intervals of at least 6 hours to a constant weight, i.e., <0.5 mg change from previous weighing; record results to the nearest 0.1 mg. During each weighing the filter must not be exposed to the laboratory atmosphere for a period greater than 2 minutes and a relative humidity above 50 percent. Alternatively (unless otherwise specified by the Administrator), the filters may be oven dried at 105° C (220° F) for 2 to 3 hours, desiccated for 2 hours, and weighed. Procedures other than those described, which account for relative humidity effects, may be used, subject to the approval of the Administrator.

4.1.2 Preliminary Determinations. Select the sampling site and the minimum number of sampling points according to Method 1 or as specified by the Administrator. Determine the stack pressure, temperature, and the range of velocity heads using Method 2; it is recommended that a leak-check of the pitot lines (see Method 2, Section 3.1) be performed. Determine the moisture content using Approximation Method 4 or its alternatives for the purpose of making isokinetic sampling rate settings. Determine the stack gas dry molecular weight, as described in Method 2, Section 3.6; if integrated Method 3 sampling is used for molecular weight determination, the integrated bag sample shall be taken simultaneously with, and for the same total length of time as, the particulate sample run.

Select a nozzle size based on the range of velocity heads, such that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates. During the run, do not change the nozzle size. Ensure that the proper differential pressure gauge is chosen for the range of velocity heads encountered (see Section 2.2 of Method 2).

Select a suitable probe liner and probe length such that all traverse points can be sampled. For large stacks, consider sampling from opposite sides of the stack to reduce the length of probes.

Select a total sampling time greater than or equal to the minimum total sampling time specified in the test procedures for the specific industry such that (1) the sampling time per point is not less than 2 min (or some greater time interval as specified by the Administrator), and (2) the sample volume taken (corrected to standard conditions) will exceed the required minimum total gas sample volume. The latter is based on an approximate average sampling rate.

It is recommended that the number of minutes sampled at each point be an integer or an integer plus one-half minute, in order to avoid timekeeping errors.

In some circumstances, e.g., batch cycles, it may be necessary to sample for shorter times at the traverse points and to obtain smaller gas sample volumes. In these cases, the Administrator's approval must first be obtained.

4.1.3 Preparation of Collection Train. During preparation and assembly of the sampling train, keep all openings where contamination can occur covered until just prior to assembly or until sampling is about to begin.

Place 100 ml of water in each of the first two impingers, leave the third impinger empty, and transfer approximately 200 to 300 g of preweighed silica gel from its container to the fourth impinger. More silica gel may be used, but care should be taken to ensure that it is not entrained and carried out from the impinger during sampling. Place the container in a clean place for later use in the sample recovery. Alternatively, the weight of the silica gel plus impinger may be determined to the nearest 0.5 g and recorded.

Using a tweezer or clean disposable surgical gloves, place a labeled (identified) and weighed filter in the filter holder. Be sure that the filter is properly centered and the gasket properly placed so as to prevent the sample gas stream from circumventing the filter. Check the filter for tears after assembly is completed.

When glass liners are used, install the selected nozzle using a Viton A O-ring when stack temperatures are less than 260° C (500° F) and an asbestos string gasket when temperatures are higher. See APTD-0576 for details. Other connecting systems using either 316 stainless steel or Teflon ferrules may be used. When metal liners are used, install the nozzle as above or by a leak-free direct mechanical connection. Mark the probe with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point.

Set up the train as in Figure 5-1, using (if necessary) a very light coat of silicone grease on all ground glass joints, greasing only the outer portion (see APTD-0576) to avoid possibility of contamination by the silicone grease. Subject to the approval of the Administrator, a glass cyclone may be used between the probe and filter holder when the total particulate catch is expected to exceed 100 mg or when water droplets are present in the stack gas.

Place crushed ice around the impingers.

4.1.4 Leak-Check Procedures.

4.1.4.1 Pretest Leak-Check. A pretest leak-check is recommended, but not required. If the tester opts to conduct the pretest leak-check, the following procedure shall be used.

After the sampling train has been assembled, turn on and set the filter and probe heating systems at the desired operating temperatures. Allow time for the temperatures to stabilize. If a Viton A O-ring or other leak-free connection is used in assembling the probe nozzle to the probe liner, leak-check the train at the sampling site by plugging the nozzle and pulling a 380 mm Hg (15 in. Hg) vacuum.

NOTE.—A lower vacuum may be used, provided that it is not exceeded during the test.

If an asbestos string is used, do not connect the probe to the train during the leak-check. Instead, leak-check the train by first plugging the inlet to the filter holder (cyclone, if applicable) and pulling a 380 mm Hg (15 in. Hg) vacuum (see Note immediately above). Then connect the probe to the train and leak-check at about 25 mm Hg (1 in. Hg) vacuum; alternatively, the probe may be leak-checked with the rest of the sampling train, in one step, at 380 mm Hg (15 in. Hg) vacuum. Leakage rates in excess of 4 percent of the average sampling rate or 0.00057 m³/min (0.02 cfm), whichever is less, are unacceptable.

The following leak-check instructions for the sampling train described in APTD-0576 and APTD-0581 may be helpful. Start the pump with bypass valve fully open and coarse adjust valve completely closed. Partially open the coarse adjust valve and slowly close the bypass valve until the desired vacuum is reached. Do not reverse direction of bypass valve; this will cause water to back up into the filter holder. If the desired vacuum is exceeded, either leak-check at this higher vacuum or end the leak check as shown below and start over.

When the leak-check is completed, first slowly remove the plug from the inlet to the probe, filter holder, or cyclone (if applicable) and immediately turn off the vacuum pump. This prevents the water in the impingers from being forced backward into the filter holder and silica gel from being entrained backward into the third impinger.

4.1.4.2 Leak-Checks During Sample Run. If, during the sampling run, a component (e.g., filter assembly or impinger) change becomes necessary, a leak-check shall be conducted immediately before the change is made. The leak-check shall be done according to the procedure outlined in Section 4.1.4.1 above, except that it shall be done at a vacuum equal to or greater than the maximum value recorded up to that point in the test. If the leakage rate is found to be no greater than 0.00057 m³/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction will need to be applied to the total volume of dry gas metered; if, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and plan to correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

Immediately after component changes, leak-checks are optional; if such leak-checks are done, the procedure outlined in Section 4.1.4.1 above shall be used.

4.1.4.3 Post-test Leak-Check. A leak-check is mandatory at the conclusion of each sampling run. The leak-check shall be done in accordance with the procedures outlined in Section 4.1.4.1, except that it shall be conducted at a vacuum equal to or greater than the maximum value reached during the sampling run. If the leakage rate is found to be no greater than 0.00057 m³/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction need be applied to the total volume of dry gas metered. If, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

4.1.5 Particulate Train Operation. During the sampling run, maintain an isokinetic sampling rate (within 10 percent of true isokinetic unless otherwise specified by the Administrator) and a temperature around the filter of 120±14° C (248±25° F), or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator.

For each run, record the data required on a data sheet such as the one shown in Figure 5-2. Be sure to record the initial dry gas meter reading. Record the dry gas meter readings at the beginning and end of each sampling time increment, when changes in flow rates are made, before and after each leak check, and when sampling is halted.

Take other readings required by Figure 5-2 at least once at each sample point during each time increment and additional readings when significant changes (20 percent variation in velocity head readings) necessitate additional adjustments in flow rate. Level and zero the manometer. Because the manometer level and zero may drift due to vibrations and temperature changes, make periodic checks during the traverse.

Clean the portholes prior to the test run to minimize the chance of sampling deposited material. To begin sampling, remove the nozzle cap, verify that the filter and probe heating systems are up to temperature, and that the pitot tube and probe are properly positioned. Position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. Nomographs are available, which aid in the rapid adjustment of the isokinetic sampling rate without excessive computations. These nomographs are designed for use when the Type S pitot tube coefficient is 0.85±0.02, and the stack gas equivalent density (dry molecular weight) is equal to 29±4. APTD-0576 details the procedure for using the nomographs. If C_p and M_d are outside the above stated ranges do not use the nomographs unless appropriate steps (see Citation 7 in Section 7) are taken to compensate for the deviations.

PLANT _____
LOCATION _____
OPERATOR _____
DATE _____
RUN NO. _____
SAMPLE BOX NO. _____
METER BOX NO. _____
METER ΔH@ _____
C FACTOR _____
PITOT TUBE COEFFICIENT, C_p _____

SCHEMATIC OF STACK CROSS SECTION

AMBIENT TEMPERATURE _____
BAROMETRIC PRESSURE _____
ASSUMED MOISTURE, % _____
PROBE LENGTH, m (ft) _____
NOZZLE IDENTIFICATION NO. _____
AVERAGE CALIBRATED NOZZLE DIAMETER, cm (in.) _____
PROBE HEATER SETTING _____
LEAK RATE, m^3/min. (cfm) _____
PROBE LINER MATERIAL _____
STATIC PRESSURE, mm Hg (in. Hg) _____
FILTER NO. _____

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	VACUUM mm Hg (in. Hg)	STACK TEMPERATURE (T_S) °C (°F)	VELOCITY HEAD (ΔP_S), mm(in.)H_2O	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER mm H_2O (in. H_2O)	GAS SAMPLE VOLUME m^3 (ft^3)	GAS SAMPLE TEMPERATURE AT DRY GAS METER		FILTER HOLDER TEMPERATURE, °C (°F)	TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °C (°F)
							INLET °C (°F)	OUTLET °C (°F)		
TOTAL							Avg.	Avg.		
AVERAGE							Avg.			

Figure 5-2. Particulate field data.

When the stack is under significant negative pressure (height of impinger stem), take care to close the coarse adjust valve before inserting the probe into the stack to prevent water from backing into the filter holder. If necessary, the pump may be turned on with the coarse adjust valve closed.

When the probe is in position, block off the openings around the probe and porthole to prevent unrepresentative dilution of the gas stream.

Traverse the stack cross-section, as required by Method 1 or as specified by the Administrator, being careful not to bump the probe nozzle into the stack walls when sampling near the walls or when removing or inserting the probe through the portholes; this minimizes the chance of extracting deposited material.

During the test run, make periodic adjustments to keep the temperature around the filter holder at the proper level; add more ice and, if necessary, salt to maintain a temperature of less than 20° C (68° F) at the condenser/silica gel outlet. Also, periodically check the level and zero of the manometer.

If the pressure drop across the filter becomes too high, making isokinetic sampling difficult to maintain, the filter may be replaced in the midst of a sample run. It is recommended that another complete filter assembly be used rather than attempting to change the filter itself. Before a new filter assembly is installed, conduct a leak-check (see Section 4.1.4.2). The total particulate weight shall include the summation of all filter assembly catches.

A single train shall be used for the entire sample run, except in cases where simultaneous sampling is required in two or more separate ducts or at two or more different locations within the same duct, or, in cases where equipment failure necessitates a change of trains. In all other situations, the use of two or more trains will be subject to the approval of the Administrator.

Note that when two or more trains are used, separate analyses of the front-half and (if applicable) impinger catches from each train shall be performed, unless identical nozzle sizes were used on all trains, in which case, the front-half catches from the individual trains may be combined (as may the impinger catches) and one analysis of front-half catch and one analysis of impinger catch may be performed. Consult with the Administrator for details concerning the calculation of results when two or more trains are used.

At the end of the sample run, turn off the coarse adjust valve, remove the probe and nozzle from the stack, turn off the pump, record the final dry gas meter reading, and conduct a post-test leak-check, as outlined in Section 4.1.4.3. Also, leak-check the pitot lines as described in Method 2, Section 3.1, the lines must pass this leak-check, in order to validate the velocity head data.

4.1.6 Calculation of Percent Isokinetic. Calculate percent isokinetic (see Calculations, Section 6) to determine whether the run was valid or another test run should be made. If there was difficulty in maintaining isokinetic rates due to source conditions, consult with the Administrator for possible variance on the isokinetic rates.

4.2 Sample Recovery. Proper cleanup procedure begins as soon as the probe is removed from the stack at the end of the sampling period. Allow the probe to cool.

When the probe can be safely handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it to prevent losing or gaining particulate matter. Do not cap off the probe tip tightly while the sampling train is cooling down as this would create a vacuum in the filter holder, thus drawing water from the impingers into the filter holder.

Before moving the sample train to the cleanup site, remove the probe from the sample train, wipe off the silicone grease, and cap the open outlet of the probe. Be careful not to lose any condensate that might be present. Wipe off the silicone grease from the filter inlet where the probe was fastened and cap it. Remove the umbilical cord from the last impinger and cap the impinger. If a flexible line is used between the first impinger or condenser and the filter holder, disconnect the line at the filter holder and let any condensed water or liquid drain into the impingers or condenser. After wiping off the silicone grease, cap off the filter holder outlet and impinger inlet. Either ground-glass stoppers, plastic caps, or serum caps may be used to close these openings.

Transfer the probe and filter-impinger assembly to the cleanup area. This area should be clean and protected from the wind so that the chances of contaminating or losing the sample will be minimized.

Save a portion of the acetone used for cleanup as a blank. Take 200 ml of this acetone directly from the wash bottle being used and place it in a glass sample container labeled "acetone blank."

Inspect the train prior to and during disassembly and note any abnormal conditions. Treat the samples as follows:

Container No. 1. Carefully remove the filter from the filter holder and place it in its identified petri dish container. Use a pair of tweezers and/or clean disposable surgical gloves to handle the filter. If it is necessary to fold the filter, do so such that the particulate cake is inside the fold. Carefully transfer to the petri dish any particulate matter and/or filter fibers which adhere to the filter holder gasket, by using a dry nylon bristle brush and/or a sharp-edged blade. Seal the container.

Container No. 2. Taking care to see that dust on the outside of the probe or other exterior surfaces does not get into the sample, quantitatively recover particulate matter or any condensate from the probe nozzle, probe

fitting, probe liner, and front half of the filter holder by washing these components with acetone and placing the wash in a glass container. Distilled water may be used instead of acetone when approved by the Administrator and shall be used when specified by the Administrator; in these cases, save a water blank and follow the Administrator's directions on analysis. Perform the acetone rinses as follows:

Carefully remove the probe nozzle and clean the inside surface by rinsing with acetone from a wash bottle and brushing with a nylon bristle brush. Brush until the acetone rinse shows no visible particles, after which make a final rinse of the inside surface with acetone.

Brush and rinse the inside parts of the Swagelok fitting with acetone in a similar way until no visible particles remain.

Rinse the probe liner with acetone by tilting and rotating the probe while squirting acetone into its upper end so that all inside surfaces will be wetted with acetone. Let the acetone drain from the lower end into the sample container. A funnel (glass or polyethylene) may be used to aid in transferring liquid washes to the container. Follow the acetone rinse with a probe brush. Hold the probe in an inclined position, squirt acetone into the upper end as the probe brush is being pushed with a twisting action through the probe; hold a sample container underneath the lower end of the probe, and catch any acetone and particulate matter which is brushed from the probe. Run the brush through the probe three times or more until no visible particulate matter is carried out with the acetone or until none remains in the probe liner on visual inspection. With stainless steel or other metal probes, run the brush through in the above prescribed manner at least six times since metal probes have small crevices in which particulate matter can be entrapped. Rinse the brush with acetone, and quantitatively collect these washings in the sample container. After the brushing, make a final acetone rinse of the probe as described above.

It is recommended that two people be used to clean the probe to minimize sample losses. Between sampling runs, keep brushes clean and protected from contamination.

After ensuring that all joints have been wiped clean of silicone grease, clean the inside of the front half of the filter holder by rubbing the surfaces with a nylon bristle brush and rinsing with acetone. Rinse each surface three times or more if needed to remove visible particulate. Make a final rinse of the brush and filter holder. Carefully rinse out the glass cyclone, also (if applicable). After all acetone washings and particulate matter have been collected in the sample container, tighten the lid on the sample container so that acetone will not leak out when it is shipped to the laboratory. Mark the height of the fluid level to determine whether or not leakage occurred during transport. Label the container to clearly identify its contents.

Container No. 3. Note the color of the indicating silica gel to determine if it has been completely spent and make a notation of its condition. Transfer the silica gel from the fourth impinger to its original container and seal. A funnel may make it easier to pour the silica gel without spilling. A rubber policeman may be used as an aid in removing the silica gel from the impinger. It is not necessary to remove the small amount of dust particles that may adhere to the impinger wall and are difficult to remove. Since the gain in weight is to be used for moisture calculations, do not use any water or other liquids to transfer the silica gel. If a balance is available in the field, follow the procedure for container No. 3 in Section 4.3.

Impinger Water. Treat the impingers as follows; Make a notation of any color or film in the liquid catch. Measure the liquid which is in the first three impingers to within ±1 ml by using a graduated cylinder or by weighing it to within ±0.5 g by using a balance (if one is available). Record the volume or weight of liquid present. This information is required to calculate the moisture content of the effluent gas.

Discard the liquid after measuring and recording the volume or weight, unless analysis of the impinger catch is required (see Note, Section 2.1.7).

If a different type of condenser is used, measure the amount of moisture condensed either volumetrically or gravimetrically.

Whenever possible, containers should be shipped in such a way that they remain upright at all times.

4.3 Analysis. Record the data required on a sheet such as the one shown in Figure 5-3. Handle each sample container as follows:

Container No. 1. Leave the contents in the shipping container or transfer the filter and any loose particulate from the sample container to a tared glass weighing dish. Desiccate for 24 hours in a desiccator containing anhydrous calcium sulfate. Weigh to a constant weight and report the results to the nearest 0.1 mg. For purposes of this Section, 4.3, the term "constant weight" means a difference of no more than 0.5 mg or 1 percent of total weight less tare weight, whichever is greater, between two consecutive weighings, with no less than 6 hours of desiccation time between weighings.

Plant _____

Date _____

Run No. _____

Filter No. _____

Amount liquid lost during transport _____

Acetone blank volume, ml _____

Acetone wash volume, ml _____

Acetone blank concentration, mg/mg (equation 5-4) _____

Acetone wash blank, mg (equation 5-5) _____

CONTAINER NUMBER	WEIGHT OF PARTICULATE COLLECTED, mg		
	FINAL WEIGHT	TARE WEIGHT	WEIGHT GAIN
1			
2			
TOTAL	X	X	
		Less acetone blank	
		Weight of particulate matter	

	VOLUME OF LIQUID WATER COLLECTED		
	IMPINGER VOLUME, ml	SILICA GEL WEIGHT, g	
FINAL			
INITIAL			
LIQUID COLLECTED			
TOTAL VOLUME COLLECTED		g*	ml

* CONVERT WEIGHT OF WATER TO VOLUME BY DIVIDING TOTAL WEIGHT INCREASE BY DENSITY OF WATER (1g/ml):

$$\frac{\text{INCREASE, g}}{\text{1 g/ml}} = \text{VOLUME WATER, ml}$$

Figure 5-3. Analytical data.

Alternatively, the sample may be oven dried at 105° C (220° F) for 2 to 3 hours, cooled in the desiccator, and weighed to a constant weight, unless otherwise specified by the Administrator. The tester may also opt to oven dry the sample at 105 ° C (220 ° F) for 2 to 3 hours, weigh the sample, and use this weight as a final weight.

Container No. 2. Note the level of liquid in the container and confirm on the analysis sheet whether or not leakage occurred during transport. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results. Measure the liquid in this container either volumetrically to ±1 ml or gravimetrically to ±0.5 g. Transfer the contents to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

Container No. 3 Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g using a balance. This step may be conducted in the field.

"Acetone Blank" Container. Measure acetone in this container either volumetrically or gravimetrically. Transfer the acetone to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a contsant weight. Report the results to the nearest 0.1 mg.

NOTE.—At the option of the tester, the contents of Container No. 2 as well as the acetone blank container may be evaporated at temperatures higher than ambient. If evaporation is done at an elevated temperature, the temperature must be below the boiling point of the solvent; also, to prevent "bumping," the evaporation process must be closely supervised, and the contents of the beaker must be swirled occasionally to maintain an even temperature. Use extreme care, as acetone is highly flammable and has a low flash point.

5. *Calibration*

Maintain a laboratory log of all calibrations.

5.1 Probe Nozzle. Probe nozzles shall be calibrated before their initial use in the field. Using a micrometer, measure the inside diameter of the nozzle to the nearest 0.025 mm (0.001 in.). Make three separate measurements using different diameters each time, and obtain the average of the measurements. The difference between the high and low numbers shall not exceed 0.1 mm (0.004 in.). When nozzles become nicked, dented, or corroded, they shall be reshaped, sharpened, and recalibrated before use. Each nozzle shall be permanently and uniquely identified.

5.2 Pitot Tube. The Type S pitot tube assembly shall be calibrated according to the procedure outlined in Section 4 of Method 2.

5.3 Metering System. Before its initial use in the field, the metering system shall be calibrated according to the procedure outlined in APTD-0576. Instead of physically adjusting the dry gas meter dial readings to correspond to the wet test meter readings, calibration factors may be used to mathematically correct the gas meter dial readings to the proper values. Before calibrating the metering system, it is suggested that a leak-check be conducted. For metering systems having diaphragm pumps, the normal leak-check procedure will not detect leakages within the pump. For these cases the following leak-check procedure is suggested. make a 10-minute calibration run at 0.00057 m³/min (0.02 cfm); at the end of the run, take the difference of the measured wet test meter and dry gas meter volumes; divide the difference by 10, to get the leak rate. The leak rate should not exceed 0.00057 m³/min (0.02 cfm).

After each field use, the calibration of the metering system shall be checked by performing three calibration runs at a single, intermediate orifice setting (based on the previous field test), with the vacuum set at the maximum value reached during the test series. To adjust the vacuum, insert a valve between the wet test meter and the inlet of the metering system. Calculate the average value of the calibration factor. If the calibration has changed by more than 5 percent, recalibrate the meter over the full range of orifice settings, as outlined in APTD-0576.

Alternative procedures, e.g., using the orifice meter coefficients, may be used, subject to the approval of the Administrator.

NOTE.—If the dry gas meter coefficient values obtained before and after a test series differ by more than 5 percent, the test series shall either be voided, or calculations for the test series shall be performed using whichever meter coefficient value (i.e., before or after) gives the lower value of total sample volume.

5.4 Probe Heater Calibration. The probe heating system shall be calibrated before its initial use in the field according to the procedure outlined in APTD-0576. Probes constructed according to APTD-0581 need not be calibrated if the calibration curves in APTD-0576 are used.

5.5 Temperature Gauges. Use the procedure in Section 4.3 of Method 2 to calibrate in-stack temperature gauges. Dial thermometers, such as are used for the dry gas meter and condenser outlet, shall be calibrated against mercury-in-glass thermometers.

5.6 Leak Check of Metering System Shown in Figure 5-1. That portion of the sampling train from the pump to the orifice meter should be leak checked prior to initial use and after each shipment. Leakage after the pump will result in less volume being recorded than is actually sampled. The following procedure is suggested (see Figure 5-4): Close the main valve on the meter box. Insert a one-hole rubber stopper with rubber tubing attached into the orifice exhaust pipe. Disconnect and vent the low side of the orifice manometer. Close off the low side orifice tap. Pressurize the system to 13 to 18 cm (5 to 7 in.) water column by blowing into the rubber tubing. Pinch off the tubing and observe the manometer for one minute. A loss of pressure on the manometer indicates a leak in the meter box; leaks, if present, must be corrected.

5.7 Barometer. Calibrate against a mercury barometer.

6. *Calculations*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after the final calculation. Other forms of the equations may be used as long as they give equivalent results.

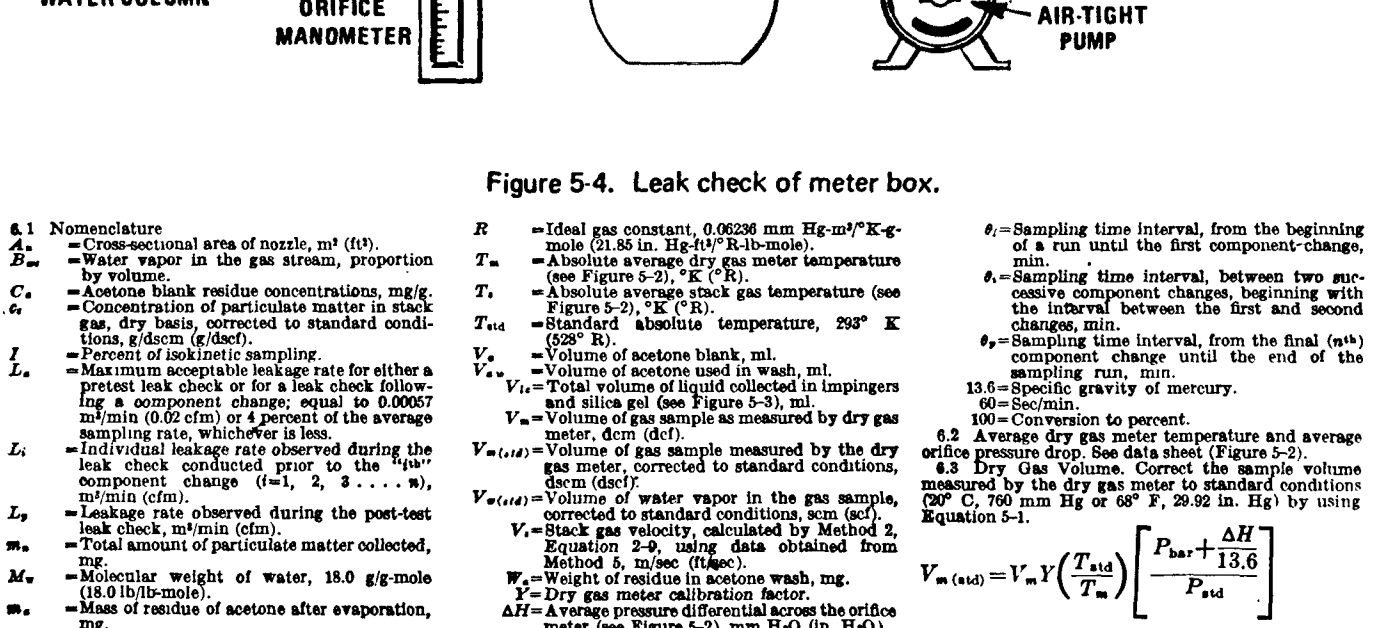


Figure 5-4. Leak check of meter box.

6.1 Nomenclature

A_n = Cross-sectional area of nozzle, m² (ft²).
B_{ws} = Water vapor in the gas stream, proportion by volume.
C_a = Acetone blank residue concentrations, mg/g.
c_s = Concentration of particulate matter in stack gas, dry basis, corrected to standard conditions, g/dscm (g/dscf).
I = Percent of isokinetic sampling.
L_a = Maximum acceptable leakage rate for either a pretest leak check or for a leak check following a component change; equal to 0.00057 m³/min (0.02 cfm) or 4 percent of the average sampling rate, whichever is less.
L_i = Individual leakage rate observed during the leak check conducted prior to the "i^{th}" component change (i=1, 2, 3 . . . . n), m³/min (cfm).
L_p = Leakage rate observed during the post-test leak check, m³/min (cfm).
m_a = Total amount of particulate matter collected, mg.
M_w = Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).
m_s = Mass of residue of acetone after evaporation, mg.
P_{bar} = Barometric pressure at the sampling site, mm Hg (in. Hg).
P_s = Absolute stack gas pressure, mm Hg (in. Hg).
P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).
R = Ideal gas constant, 0.06236 mm Hg-m³/°K-g-mole (21.85 in. Hg-ft³/°R-lb-mole).
T_m = Absolute average dry gas meter temperature (see Figure 5-2), °K (°R).
T_s = Absolute average stack gas temperature (see Figure 5-2), °K (°R).
T_{std} = Standard absolute temperature, 293° K (528° R).
V_a = Volume of acetone blank, ml.
V_{aw} = Volume of acetone used in wash, ml.
V_{lc} = Total volume of liquid collected in impingers and silica gel (see Figure 5-3), ml.
V_m = Volume of gas sample as measured by dry gas meter, dcm (dcf).
$V_{m(std)}$ = Volume of gas sample measured by the dry gas meter, corrected to standard conditions, dscm (dscf).
$V_{w(std)}$ = Volume of water vapor in the gas sample, corrected to standard conditions, scm (scf).
V_s = Stack gas velocity, calculated by Method 2, Equation 2-9, using data obtained from Method 5, m/sec (ft/sec).
W_a = Weight of residue in acetone wash, mg.
Y = Dry gas meter calibration factor.
ΔH = Average pressure differential across the orifice meter (see Figure 5-2), mm H_2O (in. H_2O).
ρ_a = Density of acetone, mg/ml (see label on bottle).
ρ_w = Density of water, 0.9982 g/ml (0.002201 lb/ml).
θ = Total sampling time, min.
θ_i = Sampling time interval, from the beginning of a run until the first component-change, min.
θ_i = Sampling time interval, between two successive component changes, beginning with the interval between the first and second changes, min.
θ_p = Sampling time interval, from the final (n^{th}) component change until the end of the sampling run, min.
13.6 = Specific gravity of mercury.
60 = Sec/min.
100 = Conversion to percent.

6.2 Average dry gas meter temperature and average orifice pressure drop. See data sheet (Figure 5-2).

6.3 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20° C, 760 mm Hg or 68° F, 29.92 in. Hg) by using Equation 5-1.

$$V_{m(std)} = V_m Y \left(\frac{T_{std}}{T_m}\right)\left[\frac{P_{bar} + \frac{\Delta H}{13.6}}{P_{std}}\right]$$

$$= K_1 V_m Y \frac{P_{bar} + (\Delta H/13.6)}{T_m}$$

Equation 5-1

where:
m_1=0.3858 °K/mm Hg for metric units
=17.64 °R/in. Hg for English units

NOTE.—Equation 5-1 can be used as written unless the leakage rate observed during any of the mandatory leak checks (i.e., the post-test leak check or leak checks conducted prior to component changes) exceeds L_a. If L_p or L_i exceeds L_a, Equation 5-1 must be modified as follows;

(a) Case I. No component changes made during sampling run. In this case, replace V_m in Equation 5-1 with the expression;

$$V_m-(L_p-L_a)\theta]$$

(b) Case II. One or more component changes made during the sampling run. In this case, replace V_m in Equation 5-1 by the expression:

$$\left[V_m-(L_1-L_a)\theta_1-\sum_{i=2}^{n}(L_i-L_a)\theta_i-(L_p-L_a)\theta_p\right]$$

and substitute only for those leakage rates (L_i or L_p) which exceed L_a.

6.4 Volume of water vapor.

$$V_{w(std)}=V_{lc}\left(\frac{\rho_w}{M_w}\right)\left(\frac{RT_{std}}{P_{std}}\right)=K_2V_{lc} \qquad \text{Equation 5-2}$$

where:
K_2=0.001333 m³/ml for metric units
=0.04707 ft³/ml for English units.

6.5 Moisture Content.

$$B_{ws}=\frac{V_{w(std)}}{V_{m(std)}+V_{w(std)}} \qquad \text{Equation 5-3}$$

NOTE.—In saturated or water droplet-laden gas streams, two calculations of the moisture content of the stack gas shall be made, one from the impinger analysis (Equation 5-3), and a second from the assumption of saturated conditions. The lower of the two values of B_{ws} shall be considered correct. The procedure for determining the moisture content based upon assumption of saturated conditions is given in the Note of Section 1.2 of Method 4. For the purposes of this method, the average stack gas temperature from Figure 5-2 may be used to make this determination, provided that the accuracy of the in-stack temperature sensor is ± 1° C (2° F).

6.6 Acetone Blank Concentration.

$$C_a=\frac{m_a}{V_a\rho_a} \qquad \text{Equation 5-4}$$

6.7 Acetone Wash Blank.

$$W_a=C_aV_{aw}\rho_a \qquad \text{Equation 5-5}$$

6.8 Total Particulate Weight. Determine the total particulate catch from the sum of the weights obtained from containers 1 and 2 less the acetone blank (see Figure 5-3). NOTE.—Refer to Section 4.1.5 to assist in calculation of results involving two or more filter assemblies or two or more sampling trains.

6.9 Particulate Concentration.

$$c_s=(0.001\ g/mg)\ (m_n/V_{m(std)}) \qquad \text{Equation 5-6}$$

6.10 Conversion Factors:

From	To	Multiply by
scf	m³	0.02832
g/ft³	gr/ft³	15.43
g/ft³	lb/ft³	2.205×10^{-3}
g/ft³	g/m³	35.31

6.11 Isokinetic Variation.
6.11.1 Calculation From Raw Data.

$$I=\frac{100\,T_s[K_3V_{lc}+(V_m/T_m)\,(P_{bar}+\Delta H/13.6)]}{60\,\theta v_s P_s A_n} \qquad \text{Equation 5-7}$$

where:
K_3=0.003454 mm Hg−m³/ml−°K for metric units.
=0.002669 in. Hg−ft³/ml−°R for English units.

6.11.2 Calculation From Intermediate Values.

$$I=\frac{T_sV_{m(std)}P_{std}100}{T_{std}v_s\theta A_nP_s60(1-B_{ws})}$$

$$=K_4\frac{T_sV_{m(std)}}{P_sV_sA_n\theta(1-B_{ws})} \qquad \text{Equation 5-8}$$

where:
K_4=4.320 for metric units
=0.09450 for English units.

6.12 Acceptable Results. If 90 percent ≤ I ≤110 percent, the results are acceptable. If the results are low in comparison to the standard and I is beyond the acceptable range, or, if I is less than 90 percent, the Administrator may opt to accept the results. Use Citation 4 to make judgments. Otherwise, reject the results and repeat the test.

7. *Bibliography*

1. Addendum to Specifications for Incinerator Testing at Federal Facilities. PHS, NCAPC. Dec. 6, 1967.
2. Martin, Robert M. Construction Details of Isokinetic Source-Sampling Equipment. Environmental Protection Agency. Research Triangle Park, N.C. APTD-0581. April, 1971.
3. Rom, Jerome J. Maintenance, Calibration, and Operation of Isokinetic Source Sampling Equipment. Environmental Protection Agency. Research Triangle Park, N.C. APTD-0576. March, 1972.
4. Smith, W. S., R. T. Shigehara, and W. F. Todd. A Method of Interpreting Stack Sampling Data. Paper Presented at the 63d Annual Meeting of the Air Pollution Control Association, St. Louis, Mo. June 14-19, 1970.
5. Smith, W. S., et al. Stack Gas Sampling Improved and Simplified With New Equipment. APCA Paper No. 67-119, 1967.
6. Specifications for Incinerator Testing at Federal Facilities. PHS, NCAPC. 1967.
7. Shigehara, R. T. Adjustments in the EPA Nomograph for Different Pitot Tube Coefficients and Dry Molecular Weights. Stack Sampling News 2:4-11. October, 1974.
8. Vollaro, R. F. A Survey of Commercially Available Instrumentation For the Measurement of Low-Range Gas Velocities. U.S. Environmental Protection Agency, Emission Measurement Branch. Research Triangle Park, N.C. November, 1976 (unpublished paper).
9. Annual Book of ASTM Standards. Part 26. Gaseous Fuels; Coal and Coke; Atmospheric Analysis. American Society for Testing and Materials. Philadelphia, Pa. 1974. pp. 617-622.

METHOD 6—DETERMINATION OF SULFUR DIOXIDE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and Applicability*

1.1 Principle. A gas sample is extracted from the sampling point in the stack. The sulfuric acid mist (including sulfur trioxide) and the sulfur dioxide are separated. The sulfur dioxide fraction is measured by the barium-thorin titration method.

1.2 Applicability. This method is applicable for the determination of sulfur dioxide emissions from stationary sources. The minimum detectable limit of the method has been determined to be 3.4 milligrams (mg) of SO_2/m³ (2.12×10^{-7} lb/ft³). Although no upper limit has been established, tests have shown that concentrations as high as 80,000 mg/m³ of SO_2 can be collected efficiently in two midget impingers, each containing 15 milliliters of 3 percent hydrogen peroxide, at a rate of 1.0 lpm for 20 minutes. Based on theoretical calculations, the upper concentration limit in a 20-liter sample is about 93,300 mg/m³.

Possible interferents are free ammonia, water-soluble cations, and fluorides. The cations and fluorides are removed by glass wool filters and an isopropanol bubbler, and hence do not affect the SO_2 analysis. When samples are being taken from a gas stream with high concentrations of very fine metallic fumes (such as in inlets to control devices), a high-efficiency glass fiber filter must be used in place of the glass wool plug (i.e., the one in the probe) to remove the cation interferents.

Free ammonia interferes by reacting with SO_2 to form particulate sulfite and by reacting with the indicator. If free ammonia is present (this can be determined by knowledge of the process and noticing white particulate matter in the probe and isopropanol bubbler), alternative methods, subject to the approval of the Administrator, U.S. Environmental Protection Agency, are required.

2. *Apparatus*

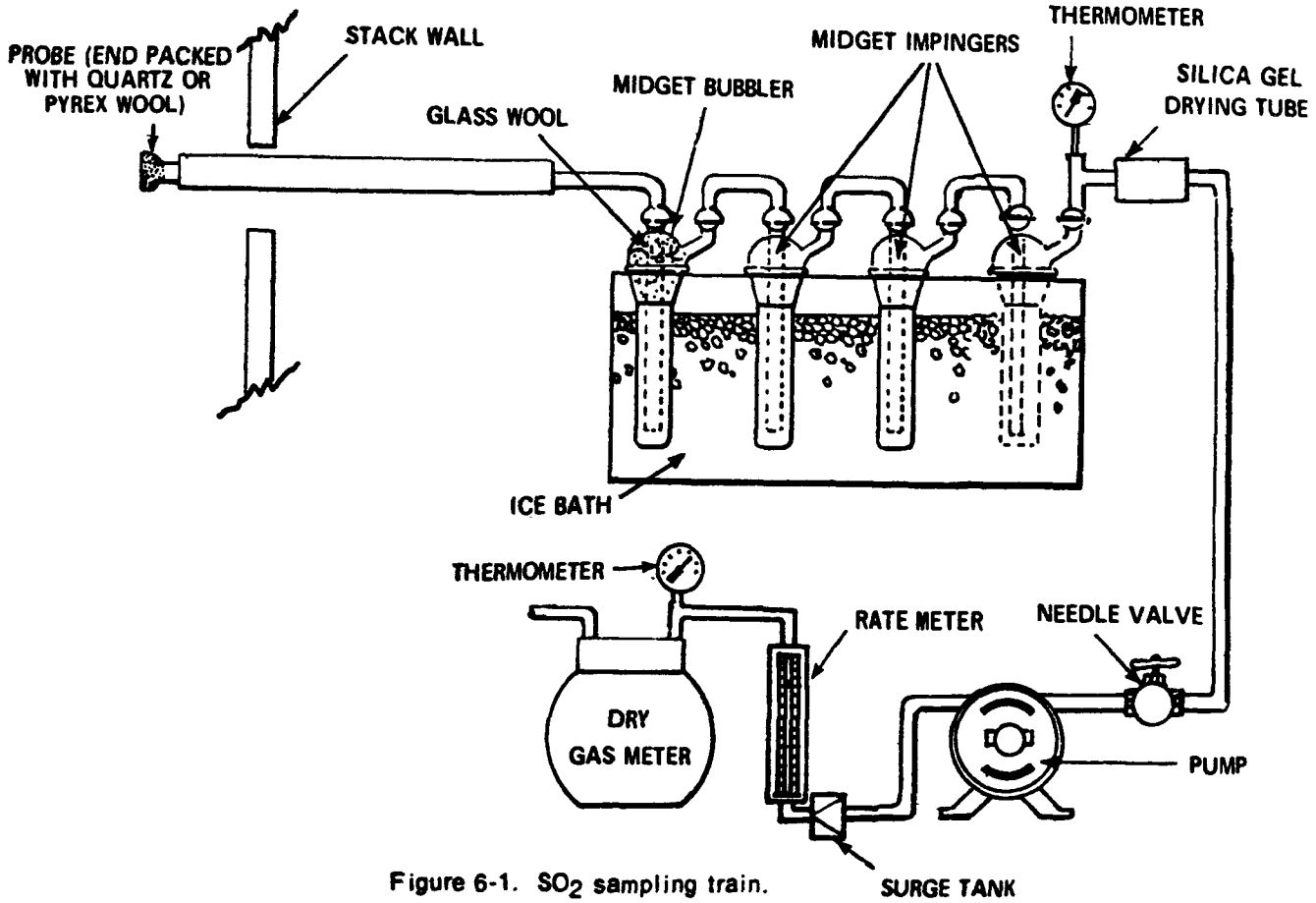


Figure 6-1. SO_2 sampling train.

2.1 Sampling. The sampling train is shown in Figure 6-1, and component parts are discussed below. The tester has the option of substituting sampling equipment described in Method 8 in place of the midget impinger equipment of Method 6. However, the Method 8 train must be modified to include a heated filter between the probe and isopropanol impinger, and the operation of the sampling train and sample analysis must be at the flow rates and solution volumes defined in Method 8.

The tester also has the option of determining SO_3 simultaneously with particulate matter and moisture determinations by (1) replacing the water in a Method 5 impinger system with 3 percent perioxide solution, or (2) by replacing the Method 5 water impinger system with a Method 8 isopropanol-filter-peroxide system. The analysis for SO_3 must be consistent with the procedure in Method 8.

2.1.1 Probe. Borosilicate glass, or stainless steel (other materials of construction may be used, subject to the approval of the Administrator), approximately 6-mm inside diameter, with a heating system to prevent water condensation and a filter (either in-stack or heated out-stack) to remove particulate matter, including sulfuric acid mist. A plug of glass wool is a satisfactory filter.

2.1.2 Bubbler and Impingers. One midget bubbler, with medium-coarse glass frit and borosilicate or quartz glass wool packed in top (see Figure 6-1) to prevent sulfuric acid mist carryover, and three 30-ml midget impingers. The bubbler and midget impingers must be connected in series with leak-free glass connectors. Silicone grease may be used, if necessary, to prevent leakage.

At the option of the tester, a midget impinger may be used in place of the midget bubbler.

Other collection absorbers and flow rates may be used, but are subject to the approval of the Administrator. Also, collection efficiency must be shown to be at least 99 percent for each test run and must be documented in the report. If the efficiency is found to be acceptable after a series of three tests, further documentation is not required. To conduct the efficiency test, an extra absorber must be added and analyzed separately. This extra absorber must not contain more than 1 percent of the total SO_2.

2.1.3 Glass Wool. Borosilicate or quartz.

2.1.4 Stopcock Grease. Acetone-insoluble, heat-stable silicone grease may be used, if necessary.

2.1.5 Temperature Gauge. Dial thermometer, or equivalent, to measure temperature of gas leaving impinger train to within 1° C (2° F.)

2.1.6 Drying Tube. Tube packed with 6- to 16-mesh indicating type silica gel, or equivalent, to dry the gas sample and to protect the meter and pump. If the silica gel has been used previously, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to approval of the Administrator.

2.1.7 Valve. Needle valve, to regulate sample gas flow rate.

2.1.8 Pump. Leak-free disphragm pump, or equivalent, to pull gas through the train. Install a small tank between the pump and rate meter to eliminate the pulsation effect of the diaphragm pump on the rotameter.

2.1.9 Rate Meter. Rotameter, or equivalent, capable of measuring flow rate to within 2 percent of the selected flow rate of about 1000 cc/min.

2.1.10 Volume Meter. Dry gas meter, sufficiently accurate to measure the sample volume within 2 percent, calibrated at the selected flow rate and conditions actually encountered during sampling, and equipped with a temperature gauge (dial thermometer, or equivalent) capable of measuring temperature to within 3°C (5.4°F).

2.1.11 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.

2.1.12 Vacuum Gauge. At least 760 mm Hg (30 in. Hg) gauge, to be used for leak check of the sampling train.

2.2 Sample Recovery.

2.2.1 Wash bottles. Polyethylene or glass, 500 ml, two.

2.2.2 Storage Bottles. Polyethylene, 100 ml, to store impinger samples (one per sample).

2.3 Analysis.

2.3.1 Pipettes. Volumetric type, 5-ml, 20-ml (one per sample), and 25-ml sizes.

2.3.2 Volumetric Flasks. 100-ml size (one per sample) and 100-ml size.

2.3.3 Burettes. 5- and 50-ml sizes.

2.3.4 Erlenmeyer Flasks. 250 ml-size (one for each sample, blank, and standard).

2.3.5 Dropping Bottle. 125-ml size, to add indicator.

2.3.6 Graduated Cylinder. 100-ml size.

2.3.7 Spectrophotometer. To measure absorbance at 352 nanometers.

3. *Reagents*

Unless otherwise indicated, all reagents must conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society. Where such specifications are not available, use the best available grade.

3.1 Sampling.

3.1.1 Water. Deionized, distilled to conform to ASTM specification D1193-74, Type 3. At the option of the analyst, the $KMnO_4$ test for oxidizable organic matter may be omitted when high concentrations of organic matter are not expected to be present.

3.1.2 Isopropanol, 80 percent. Mix 80 ml of isopropanol with 20 ml of deionized, distilled water. Check each lot of isopropanol for peroxide impurities as follows: shake 10 ml of isopropanol with 10 ml of freshly prepared 10 percent potassium iodide solution. Prepare a blank by similarly treating 10 ml of distilled water. After 1 minute, read the absorbance at 352 nanometers on a spectrophotometer. If absorbance exceeds 0.1, reject alcohol for use.

Peroxides may be removed from isopropanol by redistilling or by passage through a column of activated alumina; however, reagent grade isopropanol with suitably low peroxide levels may be obtained from commercial sources. Rejection of contaminated lots may, therefore, be a more efficient procedure.

3.1.3 Hydrogen Peroxide, 3 Percent. Dilute 30 percent hydrogen peroxide 1:9 (v/v) with deionized, distilled water (30 ml is needed per sample). Prepare fresh daily.

3.1.4 Potassium Iodide Solution, 10 Percent. Dissolve 10.0 grams KI in deionized, distilled water and dilute to 100 ml. Prepare when needed.

3.2 Sample Recovery.

3.2.1 Water. Deionized, distilled, as in 3.1.1.

3.2.2 Isopropanol, 80 Percent. Mix 80 ml of isopropanol with 20 ml of deionized, distilled water.

3.3 Analysis.

3.3.1 Water. Deionized, distilled, as in 3.1.1.

3.3.2 Isopropanol, 100 percent.

3.3.3 Thorin Indicator. 1-(o-arsonophenylazo)-2-naphthol-3,6-disulfonic acid, disodium salt, or equivalent. Dissolve 0.20 g in 100 ml of deionized, distilled water.

3.3.4 Barium Perchlorate Solution, 0.0100 N Dissolve 1.95 g of barium perchlorate trihydrate [$Ba(ClO_4)_2 \cdot 3H_2O$] in 200 ml distilled water and dilute to 1 liter with isopropanol. Alternatively, 1.22 g of [$BaCl_2 \cdot 2H_2O$] may be used instead of the perchlorate. Standardize as in Section 5.5.

3.3 5 Sulfuric Acid Standard, 0 0100 N. Purchase or standardize to ±0.0002 N against 0 0100 N NaOH which has previously been standardized against potassium acid phthalate (primary standard grade)

4 *Procedure.*

4.1 Sampling.

4 1 1 Preparation of collection train. Measure 15 ml of 80 percent isopropanol into the midget bubbler and 15 ml of 3 percent hydrogen peroxide into each of the first two midget impingers Leave the final midget impinger dry *Assemble the train as shown in Figure 6-1 Adjust* probe heater to a temperature sufficient to prevent water condensation. Place crushed ice and water around the impingers

4 1 2 Leak-check procedure A leak check prior to the sampling run is optional, however, a leak check after the sampling run is mandatory The leak-check procedure is as follows:

With the probe disconnected, place a vacuum gauge at the inlet to the bubbler and pull a vacuum of 250 mm (10 in) Hg: plug or pinch off the outlet of the flow meter, and then turn off the pump The vacuum shall remain stable for at least 30 seconds Carefully release the vacuum gauge before releasing the flow meter end to prevent back flow of the impinger fluid

Other leak check procedures may be used, subject to *the approval of the Administrator, U S Environmental* Protection Agency The procedure used in Method 5 is not suitable for diaphragm pumps

4 1 3 Sample collection Record the initial dry gas meter reading and barometric pressure. To begin sampling, position the tip of the probe at the sampling point, connect the probe to the bubbler, and start the pump Adjust the sample flow to a constant rate of approximately 1 0 liter/min as indicated by the rotameter. Maintain this constant rate (±10 percent) during the entire sampling run. Take readings (dry gas meter, temperatures at dry gas meter and at impinger outlet and rate meter) at least every 5 minutes. Add more ice during the run to keep the temperature of the gases leaving the last impinger at 20° C (68° F) or less. At the conclusion of each run, turn off the pump, remove probe *from the stack, and record the final readings. Conduct a* leak check as in Section 4.1.2. (This leak check is mandatory.) If a leak is found, void the test run. Drain the ice bath, and purge the remaining part of the train by drawing clean ambient air through the system for 15 minutes at the sampling rate.

Clean ambient air can be provided by passing air through a charcoal filter or through an extra midget impinger with 15 ml of 3 percent H_2O_2. The tester may opt to simply use ambient air, without purification.

4.2 Sample Recovery. Disconnect the impingers after purging. Discard the contents of the midget bubbler. Pour the contents of the midget impingers into a leak-free polyethylene bottle for shipment. Rinse the three midget impingers and the connecting tubes with deionized, distilled water, and add the washings to the same storage *container. Mark the fluid level. Seal and identify the* sample container.

4.3 Sample Analysis. Note level of liquid in container, and confirm whether any sample was lost during shipment; note this on analytical data sheet. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results.

Transfer the contents of the storage container to a 100-ml volumetric flask and dilute to exactly 100 ml with deionized, distilled water. Pipette a 20-ml aliquot of this solution into a 250-ml Erlenmeyer flask, add 80 ml of 100 percent isopropanol and two to four drops of thorin indicator, and titrate to a pink endpoint using 0.0100 N barium perchlorate. Repeat and average the titration volumes. Run a blank with each series of samples. Replicate titrations must agree within 1 percent or 0.2 ml, whichever is larger.

(NOTE.—Protect the 0.0100 N barium perchlorate solution from evaporation at all times.)

5. *Calibration*

5.1 Metering System.

5.1.1 Initial Calibration. Before its initial use in the field, first leak check the metering system (drying tube, needle valve, pump, rotameter, and dry gas meter) as follows: place a vacuum gauge at the inlet to the drying tube and pull a vacuum of 250 mm (10 in.) Hg; plug or pinch off the outlet or the flow meter, and then turn off the pump. The vacuum shall remain stable for at least 30 seconds. Carefully release the vacuum gauge before releasing the flow meter end.

Next, calibrate the metering system (at the sampling flow rate specified by the method) as follows: connect an appropriately sized wet test meter (e.g., 1 liter per revolution) to the inlet of the drying tube. Make three independent calibration runs, using at least five revolutions of the dry gas meter per run. Calculate the calibration factor, Y (wet test meter calibration volume divided by the dry gas meter volume, both volumes adjusted to the same reference temperature and pressure), for each run, and average the results. If any Y value deviates by more than 2 percent from the average, the metering system is unacceptable for use. Otherwise, use the average as the calibration factor for subsequent test runs.

5.1.2 Post-Test Calibration Check. After each field test series, conduct a calibration check as in Section 5.1.1 above, except for the following variations: (a) the leak check is not to be conducted, (b) three, or more revolutions of the dry gas meter may be used, and (c) only two independent runs need be made. If the calibration factor does not deviate by more than 5 percent from the initial calibration factor (determined in Section 5.1.1), then the dry gas meter volumes obtained during the test series are acceptable. If the calibration factor deviates by more than 5 percent, recalibrate the metering system as in Section 5.1.1, and for the calculations, use the calibration factor (initial or recalibration) that yields the lower gas volume for each test run.

5.2 Thermometers. Calibrate against mercury-in-glass thermometers.

5.3 Rotameter. The rotameter need not be calibrated but should be cleaned and maintained according to the manufacturer's instruction.

5.4 Barometer. Calibrate against a mercury barometer.

5.5 Barium Perchlorate Solution. Standardize the barium perchlorate solution against 25 ml of standard sulfuric acid to which 100 ml of 100 percent isopropanol has been added.

6. *Calculations*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

6.1 Nomenclature.

C_{so_2} = Concentration of sulfur dioxide, dry basis corrected to standard conditions, mg/dscm (lb/dscf).

N = Normality of barium perchlorate titrant, milliequivalents/ml.

P_{bar} = Barometric pressure at the exit orifice of the dry gas meter, mm Hg (in. Hg).

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

T_m = Average dry gas meter absolute temperature, °K (°R).

T_{std} = Standard absolute temperature, 293° K (528° R).

V_a = Volume of sample aliquot titrated, ml.

V_m = Dry gas volume as measured by the dry gas meter, dcm (dcf).

$V_{m(std)}$ = Dry gas volume measured by the dry gas meter, corrected to standard conditions, dscm (dscf).

V_{soln} = Total volume of solution in which the sulfur dioxide sample is contained, 100 ml.

V_t = Volume of barium perchlorate titrant used for the sample, ml (average of replicate titrations).

V_{tb} = Volume of barium perchlorate titrant used for the blank, ml.

Y = Dry gas meter calibration factor.

32.03 = Equivalent weight of sulfur dioxide.

6.2 Dry sample gas volume, corrected to standard conditions.

$$V_{m(std)} = V_m Y \left(\frac{T_{std}}{T_m}\right)\left(\frac{P_{bar}}{P_{std}}\right) = K_1 Y \frac{V_m P_{bar}}{T_m}$$

Equation 6-1

where:

K_1 = 0.3858 °K/mm Hg for metric units.
= 17.64 °R/in. Hg for English units.

6.3 Sulfur dioxide concentration.

$$C_{SO_2} = K_1 \frac{(V_t - V_{tb})\ N\left(\frac{V_{soln}}{V_a}\right)}{V_{m(std)}}$$

Equation 6-2

where:

K_1 = 32 03 mg/meq. for metric units.
= 7.061×10⁻⁵ lb/meq. for English units.

7. *Bibliography*

1. Atmospheric Emissions from Sulfuric Acid Manufacturing Processes. U.S. DHEW, PHS, Division of Air Pollution Public Health Service Publication No. 999-AP-13. Cincinnati, Ohio. 1965.

2. Corbett, P. F. The Determination of SO_2 and SO_3 in Flue Gases. Journal of the Institute of Fuel. *24:* 237-243, 1961.

3. Matty, R. E. and E. K. Diehl. Measuring Flue-Gas SO_2 and SO_3. Power. *101:* 94-97. November 1957.

4. Patton, W. F. and J. A. Brink, Jr. New Equipment and Techniques for Sampling Chemical Process Gases. J. Air Pollution Control Association. *13:* 162. 1963.

5. Rom, J. J. Maintenance, Calibration, and Operation of Isokinetic Source-Sampling Equipment. Office of Air Programs, Environmental Protection Agency. Research Triangle Park, N.C. APTD-0576. March 1972.

6. Hamil, H. F. and D. E. Camann. Collaborative Study of Method for the Determination of Sulfur Dioxide Emissions from Stationary Sources (Fossil-Fuel Fired Steam Generators). Environmental Protection Agency, Research Triangle Park, N.C. EPA-650/4-74-024. December 1973.

7. Annual Book of ASTM Standards. Part 31; Water, Atmospheric Analysis. American Society for Testing and Materials. Philadelphia, Pa. 1974. pp. 40-42.

8. Knoll, J. E. and M. R. Midgett. The Application of EPA Method 6 to High Sulfur Dioxide Concentrations. Environmental Protection Agency. Research Triangle Park, N.C. EPA-600/4-76-038. July 1976.

METHOD 7—DETERMINATION OF NITROGEN OXIDE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and Applicability*

1.1 Principle. A grab sample is collected in an evacuated flask containing a dilute sulfuric acid-hydrogen peroxide absorbing solution, and the nitrogen oxides, except nitrous oxide, are measured colorimeterically using the phenoldisulfonic acid (PDS) procedure.

1.2 Applicability. This method is applicable to the measurement of nitrogen oxides emitted from stationary sources. The range of the method has been determined to be 2 to 400 milligrams NO_x (as NO_2) per dry standard cubic meter, without having to dilute the sample.

2. *Apparatus*

2.1 Sampling (see Figure 7-1). Other grab sampling systems or equipment, capable of measuring sample volume to within ±2.0 percent and collecting a sufficient sample volume to allow analytical reproducibility to within ±5 percent, will be considered acceptable alternatives, subject to approval of the Administrator, U.S. Environmental Protection Agency. The following equipment is used in sampling:

2.1.1 Probe. Borosilicate glass tubing, sufficiently heated to prevent water condensation and equipped with an *in-stack or out-stack filter to remove particulate* matter (a plug of glass wool is satisfactory for this purpose). Stainless steel or Teflon [3] tubing may also be used for the probe. Heating is not necessary if the probe remains dry during the purging period.

[3] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

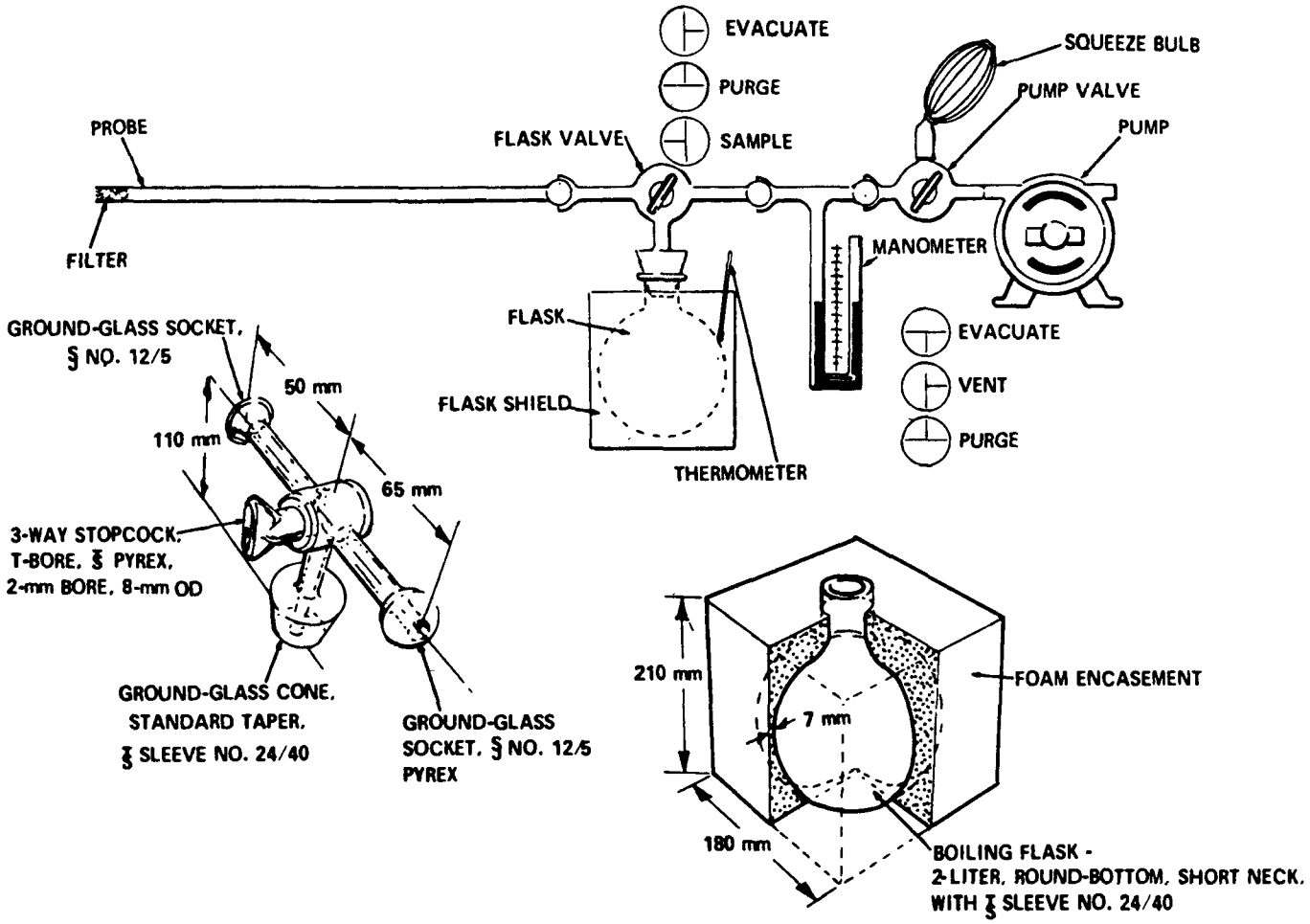


Figure 7-1. Sampling train, flask valve, and flask.

2.1.2 Collection Flask. Two-liter borosilicate, round bottom flask, with short neck and 24/40 standard taper opening, protected against implosion or breakage.

2.1.3 Flask Valve. T-bore stopcock connected to a 24/40 standard taper joint.

2.1.4 Temperature Gauge. Dial-type thermometer, or other temperature gauge, capable of measuring 1° C (2° F) intervals from −5 to 50° C (25 to 125° F).

2.1.5 Vacuum Line. Tubing capable of withstanding a vacuum of 75 mm Hg (3 in. Hg) absolute pressure, with "T" connection and T-bore stopcock.

2.1.6 Vacuum Gauge. U-tube manometer, 1 meter (36 in.), with 1-mm (0.1-in.) divisions, or other gauge capable of measuring pressure to within ±2.5 mm Hg (0.10 in. Hg).

2.1.7 Pump. Capable of evacuating the collection flask to a pressure equal to or less than 75 mm Hg (3 in. Hg) absolute.

2.1.8 Squeeze Bulb. One-way.

2.1.9 Volumetric Pipette. 25 ml.

2.1.10 Stopcock and Ground Joint Grease. A high-vacuum, high-temperature chlorofluorocarbon grease is required. Halocarbon 25-5S has been found to be effective.

2.1.11 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase, or vice versa for elevation decrease.

2.2 Sample Recovery. The following equipment is required for sample recovery

2.2.1 Graduated Cylinder. 50 ml with 1-ml divisions.

2.2.2 Storage Containers. Leak-free polyethylene bottles.

2.2.3 Wash Bottle. Polyethylene or glass

2.2.4 Glass Stirring Rod.

2.2.5 Test Paper for Indicating pH. To cover the pH range of 7 to 14.

2.3 Analysis. For the analysis, the following equipment is needed.

2.3.1 Volumetric Pipettes. Two 1 ml, two 2 ml, one 3 ml, one 4 ml, two 10 ml, and one 25 ml for each sample and standard.

2.3.2 Porcelain Evaporating Dishes. 175- to 250-ml capacity with lip for pouring, one for each sample and each standard. The Coors No. 45006 (shallow-form, 195 ml) has been found to be satisfactory. Alternatively, polymethyl pentene beakers (Nalge No. 1203, 150 ml), or glass beakers (150 ml) may be used. When glass beakers are used, etching of the beakers may cause solid matter to be present in the analytical step, the solids should be removed by filtration (see Section 4.3).

2.3.3 Steam Bath Low-temperature ovens or thermostatically controlled hot plates kept below 70° C (160° F) are acceptable alternatives

2.3.4 Dropping Pipette or Dropper. Three required.

2.3.5 Polyethylene Policeman. One for each sample and each standard.

2.3.6 Graduated Cylinder. 100 ml with 1-ml divisions.

2.3.7 Volumetric Flasks. 50 ml (one for each sample), 100 ml (one for each sample and each standard, and one for the working standard KNO_3 solution), and 1000 ml (one).

2.3.8 Spectrophotometer. To measure absorbance at 410 nm.

2.3.9 Graduated Pipette. 10 ml with 0.1-ml divisions.

2.3.10 Test Paper for Indicating pH. To cover the pH range of 7 to 14.

2.3.11 Analytical Balance. To measure to within 0.1 mg.

3. *Reagents*

Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available; otherwise, use the best available grade.

3.1 Sampling. To prepare the absorbing solution, cautiously add 2.8 ml concentrated H_2SO_4 to 1 liter of deionized, distilled water. Mix well and add 6 ml of 3 percent hydrogen peroxide, freshly prepared from 30 percent hydrogen peroxide solution. The absorbing solution should be used within 1 week of its preparation. Do not expose to extreme heat or direct sunlight

3.2 Sample Recovery. Two reagents are required for sample recovery:

3.2.1 Sodium Hydroxide (1N). Dissolve 40 g NaOH in deionized, distilled water and dilute to 1 liter.

3.2.2 Water. Deionized, distilled to conform to ASTM specification D1193-74, Type 3. At the option of the analyst, the $KMNO_4$ test for oxidizable organic matter may be omitted when high concentrations of organic matter are not expected to be present

3.3 Analysis. For the analysis, the following reagents are required:

3.3.1 Fuming Sulfuric Acid. 15 to 18 percent by weight free sulfur trioxide. HANDLE WITH CAUTION.

3.3.2 Phenol. White solid.

3.3.3 Sulfuric Acid. Concentrated, 95 percent minimum assay. HANDLE WITH CAUTION.

3.3.4 Potassium Nitrate. Dried at 105 to 110° C (220 to 230° F) for a minimum of 2 hours just prior to preparation of standard solution.

3.3.5 Standard KNO_3 Solution. Dissolve exactly 2.198 g of dried potassium nitrate (KNO_3) in deionized, distilled water and dilute to 1 liter with deionized, distilled water in a 1,000-ml volumetric flask.

3.3.6 Working Standard KNO_3 Solution. Dilute 10 ml of the standard solution to 100 ml with deionized distilled water. One milliliter of the working standard solution is equivalent to 100 μg nitrogen dioxide (NO_2).

3.3.7 Water. Deionized, distilled as in Section 3.2.2.

3.3.8 Phenoldisulfonic Acid Solution. Dissolve 25 g of pure white phenol in 150 ml concentrated sulfuric acid on a steam bath. Cool, add 75 ml fuming sulfuric acid, and heat at 100° C (212° F) for 2 hours. Store in a dark, stoppered bottle.

4. *Procedures*

4.1 Sampling.

4.1.1 Pipette 25 ml of absorbing solution into a sample flask, retaining a sufficient quantity for use in preparing the calibration standards. Insert the flask valve stopper into the flask with the valve in the "purge" position. Assemble the sampling train as shown in Figure 7-1 and place the probe at the sampling point. Make sure that all fittings are tight and leak-free, and that all ground glass joints have been properly greased with a high-vacuum, high-temperature chlorofluorocarbon-based stopcock grease. Turn the flask valve and the pump valve to their "evacuate" positions. Evacuate the flask to 75 mm Hg (3 in. Hg) absolute pressure, or less. Evacuation to a pressure approaching the vapor pressure of water at the existing temperature is desirable. Turn the pump valve to its "vent" position and turn off the pump. Check for leakage by observing the manometer for any pressure fluctuation. (Any variation

greater than 10 mm Hg (0.4 in Hg) over a period of 1 minute is not acceptable, and the flask is not to be used until the leakage problem is corrected. Pressure in the flask is not to exceed 75 mm Hg (3 in. Hg) absolute at the time sampling is commenced) Record the volume of the flask and valve (V_f), the flask temperature (T_f), and the barometric pressure Turn the flask valve counterclockwise to its "purge" position and do the same with the pump valve. Purge the probe and the vacuum tube using the squeeze bulb. If condensation occurs in the probe and the flask valve area, heat the probe and purge until the condensation disappears. Next, turn the pump valve to its "vent" position. Turn the flask valve clockwise to its "evacuate" position and record the difference in the mercury levels in the manometer. The absolute internal pressure in the flask (P_f) is equal to the barometric pressure less the manometer reading. Immediately turn the flask valve to the "sample" position and permit the gas to enter the flask until pressures in the flask and sample line (i e , duct, stack) are equal. This will usually require about 15 seconds; a longer period indicates a "plug" in the probe, which must be corrected before sampling is continued. After collecting the sample, turn the flask valve to its "purge" position and disconnect the flask from the sampling train. Shake the flask for at least 5 minutes.

4.1.2 If the gas being sampled contains insufficient oxygen for the conversion of NO to NO_2 (e.g., an applicable subpart of the standard may require taking a sample of a calibration gas mixture of NO in N_2), then oxygen shall be introduced into the flask to permit this conversion. Oxygen may be introduced into the flask by one of three methods; (1) Before evacuating the sampling flask, flush with pure cylinder oxygen, then evacuate flask to 75 mm Hg (3 in. Hg) absolute pressure or less, or (2) inject oxygen into the flask after sampling; or (3) terminate sampling with a minimum of 50 mm Hg (2 in Hg) vacuum remaining in the flask, record this final pressure, and then vent the flask to the atmosphere until the flask pressure is almost equal to atmospheric pressure.

4.2 Sample Recovery. Let the flask set for a minimum of 16 hours and then shake the contents for 2 minutes Connect the flask to a mercury filled U-tube manometer. Open the valve from the flask to the manometer and record the flask temperature (T_f), the barometric pressure, and the difference between the mercury levels n the manometer. The absolute internal pressure in the flask (P_f) is the barometric pressure less the manometer reading Transfer the contents of the flask to a leak-free polyethylene bottle. Rinse the flask twice with 5-ml portions of deionized, distilled water and add the rinse water to the bottle Adjust the pH to between 9 and 12 by adding sodium hydroxide (1 N), dropwise (about 25 to 35 drops). Check the pH by dipping a stirring rod into the solution and then touching the rod to the pH test paper Remove as little material as possible during this step. Mark the height of the liquid level so that the container can be checked for leakage after transport. Label the container to clearly identify its contents. Seal the container for shipping.

4.3 Analysis. Note the level of the liquid in container and confirm whether or not any sample was lost during shipment; note this on the analytical data sheet. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results. Immediately prior to analysis, transfer the contents of the shipping container to a 50-ml volumetric flask, and rinse the container twice with 5-ml portions of deionized, distilled water. Add the rinse water to the flask and dilute to the mark with deionized, distilled water; mix thoroughly. Pipette a 25-ml aliquot into the procelain evaporating dish. Return any unused portion of the sample to the polyethylene storage bottle. Evaporate the 25-ml aliquot to dryness on a steam bath and allow to cool. Add 2 ml phenoldisulfonic acid solution to the dried residue and triturate thoroughly with a poylethylene policeman. Make sure the solution contacts all the residue. Add 1 ml deionized, distilled water and four drops of concentrated sulfuric acid. Heat the solution on a steam bath for 3 minutes with occasional stirring. Allow the solution to cool, add 20 ml deionized, distilled water, mix well by stirring, and add concentrated ammonium hydroxide, dropwise, with constant stirring, until the pH is 10 (as determined by pH paper). If the sample contains solids, these must be removed by filtration (centrifugation is an acceptable alternative, subject to the approval of the Administrator), as follows. filter through Whatman No. 41 filter paper into a 100-ml volumetric flask; rinse the evaporating dish with three 5-ml portions of deionized, distilled water; filter these three rinses. Wash the filter with at least three 15-ml portions of deionized, distilled water. Add the filter washings to the contents of the volumetric flask and dilute to the mark with deionized, distilled water. If solids are absent, the solution can be transferred directly to the 100-ml volumetric flask and diluted to the mark with deionized, distilled water. Mix the contents of the flask thoroughly, and measure the absorbance at the optimum wavelength used for the standards (Section 5.2.1), using the blank solution as a zero reference. Dilute the sample and the blank with equal volumes of deionized, distilled water if the absorbance exceeds A_4, the absorbance of the 400 μg NO_2 standard (see Section 5.2.2).

5 *Calibration*

5 1 Flask Volume. The volume of the collection flask-flask valve combination must be known prior to sampling. Assemble the flask and flask valve and fill with water, to the stopcock Measure the volume of water to ±10 ml Record this volume on the flask.

5 2 Spectrophotometer Calibration.

5 2.1 Optimum Wavelength Determination. For both fixed and variable wavelength spectrophotometers, calibrate against standard certified wavelength of 410 nm, every 6 months. Alternatively, for variable wave length spectrophotometers, scan the spectrum between 400 and 415 nm using a 200 μg NO_2 standard solution (see Section 5.2 2). If a peak does not occur, the spectrophotometer is probably malfunctioning, and should be repaired. When a peak is obtained within the 400 to 415 nm range, the wavelength at which this peak occurs shall be the optimum wavelength for the measurement of absorbance for both the standards and samples.

5 2.2 Determination of Spectrophotometer Calibration Factor K_c. Add 0 0, 1 0, 2 0, 3.0, and 4.0 ml of the KNO_3 working standard solution (1 ml=100 μg NO_2) to a series of five porcelain evaporating dishes. To each, add 25 ml of absorbing solution, 10 ml deionized, distilled water, and sodium hydroxide (1N), dropwise, until the pH is between 9 and 12 (about 25 to 35 drops each). Beginning with the evaporation step, follow the analysis procedure of Section 4.3, until the solution has been transferred to the 100 ml volumetric flask and diluted to the mark Measure the absorbance of each solution, at the optimum wavelength, as determined in Section 5 2 1. This calibration procedure must be repeated on each day that samples are analyzed Calculate the spectrophotometer calibration factor as follows:

$$K_c = 100\,\frac{A_1+2A_2+3A_3+4A_4}{A_1^2+A_2^2+A_3^2+A_4^2}$$

Equation 7-1

where:
K_c=Calibration factor
A_1=Absorbance of the 100-μg NO_2 standard
A_2=Absorbance of the 200-μg NO_2 standard
A_3=Absorbance of the 300-μg NO_2 standard
A_4=Absorbance of the 400-μg NO_2 standard

5.3 Barometer. Calibrate against a mercury barometer.

5.4 Temperature Gauge. Calibrate dial thermometers against mercury-in-glass thermometers.

5.5 Vacuum Gauge. Calibrate mechanical gauges, if used, against a mercury manometer such as that specified in 2.1.6.

5.6 Analytical Balance. Calibrate against standard weights.

6. *Calculations*

Carry out the calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculations.

6.1 Nomenclature.
A=Absorbance of sample.
C=Concentration of NO_x as NO_2, dry basis, corrected to standard conditions, mg/dscm (lb/dscf).
F=Dilution factor (i e , 25/5, 25/10, etc., required only if sample dilution was needed to reduce the absorbance into the range of calibration).
K_c=Spectrophotometer calibration factor.
m=Mass of NO_x as NO_2 in gas sample, μg.
P_f=Final absolute pressure of flask, mm Hg (in. Hg).
P_i=Initial absolute pressure of flask, mm Hg (in. Hg).
P_{std}=Standard absolute pressure, 760 mm Hg (29.92 in. Hg).
T_f=Final absolute temperature of flask ,°K (°R).
T_i=Initial absolute temperature of flask, °K (°R).
T_{std}=Standard absolute temperature, 293° K (528° R)
V_{sc}=Sample volume at standard conditions (dry basis), ml.
V_f=Volume of flask and valve, ml.
V_a=Volume of absorbing solution, 25 ml
2=50/25, the aliquot factor. (If other than a 25-ml aliquot was used for analysis, the corresponding factor must be substituted).

6.2 Sample volume, dry basis, corrected to standard conditions.

$$V_{sc}=\frac{T_{std}}{P_{std}}\,(V_f-V_a)\left[\frac{P_f}{T_f}-\frac{P_i}{T_i}\right]$$

$$=K_1(V_f-25\text{ ml})\left[\frac{P_f}{T_f}-\frac{P_i}{T_i}\right]$$

Equation 7-2

where:

$$K_1=0.3858\,\frac{°K}{\text{mm Hg}}\text{ for metric units}$$

$$=17.64\,\frac{°R}{\text{in. Hg}}\text{ for English units}$$

6.3 Total μg NO_2 per sample.

$$m=2\,K_c\,AF$$

Equation 7-3

NOTE.—If other than a 25-ml aliquot is used for analysis, the factor 2 must be replaced by a corresponding factor.

6.4 Sample concentration, dry basis, corrected to standard conditions.

$$C=K_2\,\frac{m}{V_{sc}}$$

Equation 7-4

where:

$$K_2=10^3\,\frac{\text{mg/m}^3}{\mu\text{g/ml}}\text{ for metric units}$$

$$=6.243\times10^{-5}\,\frac{\text{lb/scf}}{\mu\text{g/ml}}\text{ for English units}$$

7. *Bibliography*

1. Standard Methods of Chemical Analysis. 6th ed. New York, D. Vna Nostrand Co., Inc. 1962. Vol. 1, p. 329-330.

2. Standard Method of Test for Oxides of Nitrogen in Gaseous Combustion Products (Phenoldisulfonic Acid Procedure). In: 1968 Book of ASTM Standards, Part 26. Philadelphia, Pa. 1968. ASTM Designation D-1608-60, p. 725-729.

3. Jacob, M. B. The Chemical Analysis of Air Pollutants. New York. Interscience Publishers, Inc. 1960. Vol. 10, p. 351-356.

4. Beatty, R. L., L. B. Berger, and H. H. Schrenk. Determination of Oxides of Nitrogen by the Phenoldisulfonic Acid Method. Bureau of Mines, U.S. Dept. of Interior. R. I. 3687. February 1943.

5. Hamil, H. F. and D. E. Camann. Collaborative Study of Method for the Determination of Nitrogen Oxide Emissions from Stationary Sources (Fossil Fuel-Fired Steam Generators). Southwest Research Institute report for Environmental Protection Agency. Research Triangle Park, N.C. October 5, 1973.

6. Hamil, H. F. and R. E. Thomas. Collaborative Study of Method for the Drtermination of Nitrogen Oxide Emissions from Stationary Sources (Nitric Acid Plants). Southwest Research Institute report for Environmental Protection Agency. Research Triangle Park, N.C. May 8, 1974.

METHOD 8—DETERMINATION OF SULFURIC ACID MIST AND SULFUR DIOXIDE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and Applicability*

1.1 Principle. A gas sample is extracted isokinetically from the stack. The sulfuric acid mist (including sulfur trioxide) and the sulfur dioxide are separated, and both fractions are measured separately by the barium-thorin titration method.

1.2 Applicability. This method is applicable for the determination of sulfuric acid mist (including sulfur trioxide, and in the absence of other particulate matter) and sulfur dioxide emissions from stationary sources. Collaborative tests have shown that the minimum detectable limits of the method are 0.05 milligrams/cubic meter (0.03×10^{-7} pounds/cubic foot) for sulfur trioxide and 1.2 mg/m³ (0.74 10^{-7} lb/ft³) for sulfur dioxide. No upper limits have been established. Based on theoretical calculations for 200 milliliters of 3 percent hydrogen peroxide solution, the upper concentration limit for sulfur dioxide in a 1.0 m³ (35.3 ft³) gas sample is about 12,500 mg/m³ (7.7×10^{-4} lb/ft³). The upper limit can be extended by increasing the quantity of peroxide solution in the impingers.

Possible interfering agents of this method are fluorides, free ammonia, and dimethyl aniline. If any of these interfering agents are present (this can be determined by knowledge of the process), alternative methods, subject to the approval of the Administrator, are required.

Filterable particulate matter may be determined along with SO_3 and SO_2 (subject to the approval of the Administrator); however, the procedure used for particulate matter must be consistent with the specifications and procedures given in Method 5.

2. *Apparatus*

2.1 Sampling. A schematic of the sampling train used in this method is shown in Figure 8-1; it is similar to the Method 5 train except that the filter position is different and the filter holder does not have to be heated. Commercial models of this train are available. For those who desire to build their own, however, complete construction details are described in APTD-0581. Changes from the APTD-0581 document and allowable modifications to Figure 8-1 are discussed in the following subsections.

The operating and maintenance procedures for the sampling train are described in APTD-0576. Since correct usage is important in obtaining valid results, all users should read the APTD-0576 document and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein. Further details and guidelines on operation and maintenance are given in Method 5 and should be read and followed whenever they are applicable.

2.1.1 Probe Nozzle. Same as Method 5, Section 2.1.1.

2.1.2 Probe Liner. Borosilicate or quartz glass, with a heating system to prevent visible condensation during sampling. Do not use metal probe liners.

2.1.3 Pitot Tube. Same as Method 5, Section 2.1.3.

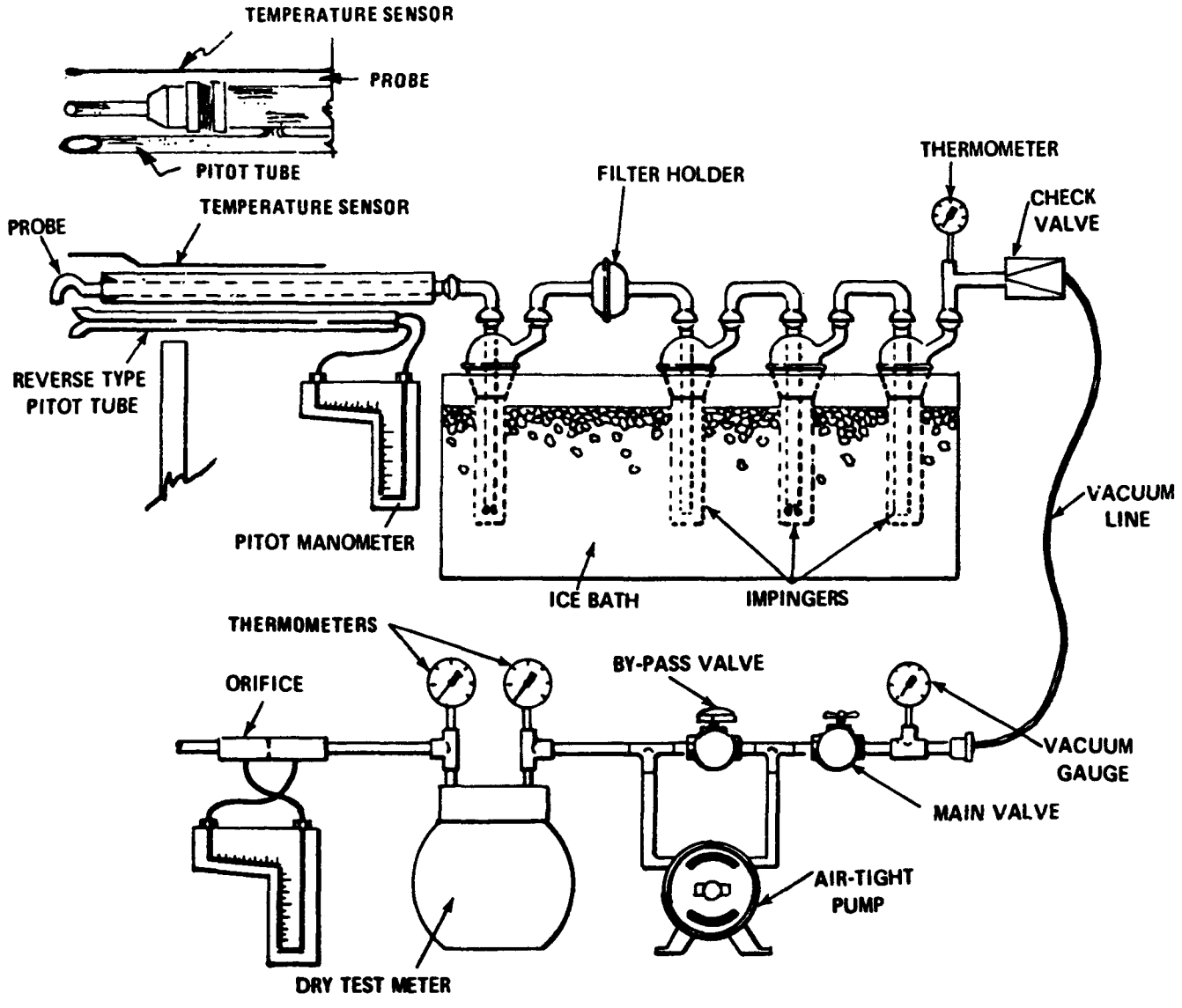


Figure 8-1. Sulfuric acid mist sampling train.

2.1.4 Differential Pressure Gauge. Same as Method 5, Section 2.1.4.

2.1.5 Filter Holder. Borosilicate glass, with a glass frit filter support and a silicone rubber gasket. Other gasket materials, e.g., Teflon or Viton, may be used subject to the approval of the Administrator. The holder design shall provide a positive seal against leakage from the outside or around the filter. The filter holder shall be placed between the first and second impingers. Note: Do not heat the filter holder.

2.1.6 *Impingers—Four, as shown in Figure 8-1.* The first and third shall be of the Greenburg-Smith design with standard tips. The second and fourth shall be of the Greenburg-Smith design, modified by replacing the insert with an approximately 13 millimeter (0.5 in.) ID glass tube, having an unconstricted tip located 13 mm (0.5 in.) from the bottom of the flask. Similar collection systems, which have been approved by the Administrator, may be used.

2.1.7 Metering System. Same as Method 5, Section 2.1.8.

2.1.8 Barometer. Same as Method 5, Section 2.1.9.

2.1.9 Gas Density Determination Equipment. Same as Method 5, Section 2.1.10.

2.1.10 Temperature Gauge. Thermometer, or equivalent, to measure the temperature of the gas leaving the impinger train to within 1° C (2° F).

2.2 *Sample Recovery.*

2.2.1 Wash Bottles. Polyethylene or glass, 500 ml. (two).

2.2.2 Graduated Cylinders. 250 ml, 1 liter. (Volumetric flasks may also be used.)

2.2.3 Storage Bottles. Leak-free polyethylene bottles, 1000 ml size (two for each sampling run).

2.2.4 Trip Balance. 500-gram capacity, to measure to ±0.5 g (necessary only if a moisture content analysis is to be done).

2.3 Analysis.

2.3.1 Pipettes. Volumetric 25 ml, 100 ml.

2.3.2 Burrette. 50 ml.

2.3.3 Erlenmeyer Flask. 250 ml. (one for each sample blank and standard).

2.3.4 Graduated Cylinder. 100 ml.

2.3.5 Trip Balance. 500 g capacity, to measure to ±0.5 g.

2.3.6 Dropping Bottle. To add indicator solution, 125-ml size.

3. *Reagents*

Unless otherwise indicated, all reagents are to conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available. Otherwise, use the best available grade.

3.1 Sampling.

3.1.1 Filters. Same as Method 5, Section 3.1.1.

3.1.2 Silica Gel. Same as Method 5, Section 3.1.2.

3.1.3 Water. Deionized, distilled to conform to ASTM specification D1193-74, Type 3. At the option of the analyst, the $KMnO_4$ test for oxidizable organic matter may be omitted when high concentrations of organic matter are not expected to be present.

3.1.4 Isopropanol, 80 Percent. Mix 800 ml of isopropanol with 200 ml of deionized, distilled water.

NOTE.—Experience has shown that only A.C.S. grade isopropanol is satisfactory. Tests have shown that isopropanol obtained from commercial sources occasionally has peroxide impurities that will cause erroneously high sulfuric acid mist measurement. Use the following test for detecting peroxides in each lot of isopropanol: Shake 10 ml of the isopropanol with 10 ml of freshly prepared 10 percent potassium iodide solution. Prepare a blank by similarly treating 10 ml of distilled water. After 1 minute, read the absorbance on a spectrophotometer at 352 nanometers. If the absorbance exceeds 0.1, the isopropanol shall not be used. Peroxides may be removed from isopropanol by redistilling, or by passage through a column of activated alumina. However, reagent-grade isopropanol with suitably low peroxide levels is readily available from commercial sources; therefore, rejection of contaminated lots may be more efficient than following the peroxide removal procedure.

3.1.5 Hydrogen Peroxide, 3 Percent. Dilute 100 ml of 30 percent hydrogen peroxide to 1 liter with deionized, distilled water. Prepare fresh daily.

3.1.6 Crushed Ice.

3.2 Sample Recovery.

3.2.1 Water. Same as 3.1.3.

3.2.2 Isopropanol, 80 Percent. Same as 3.1.4.

3.3 Analysis.

3.3.1 Water. Same as 3.1.3.

3.3.2 Isopropanol, 100 Percent.

3.3.3 Thorin Indicator. 1-(o-arsonophenylazo)-2-naphthol-3, 6-disulfonic acid, disodium salt, or equivalent. Dissolve 0.20 g in 100 ml of deionized, distilled water.

3.3.4 Barium Perchlorate (0.0100 Normal). Dissolve 1.95 g of barium perchlorate trihydrate ($Ba(ClO_4)_2 \cdot 3H_2O$) in 200 ml deionized, distilled water, and dilute to 1 liter with isopropanol; 1.22 g of barium chloride dihydrate ($BaCl_2 \cdot 2H_2O$) may be used instead of the barium perchlorate. Standardize with sulfuric acid as in Section 5.2. This solution must be protected against evaporation at all times.

3.3.5 Sulfuric Acid Standard (0.0100 N). Purchase or standardize to ±0.0002 N against 0.0100 N NaOH that has previously been standardized against primary standard potassium acid phthalate.

4. *Procedure*

4.1 Sampling.

4.1.1 Pretest Preparation. Follow the procedure outlined in Method 5, Section 4.1.1; filters should be inspected, but need not be desiccated, weighed, or identified. If the effluent gas can be considered dry, i.e., moisture free, the silica gel need not be weighed.

4.1.2 Preliminary Determinations. Follow the procedure outlined in Method 5, Section 4.1.2.

4.1.3 Preparation of Collection Train. Follow the procedure outlined in Method 5, Section 4.1.3 (except for the second paragraph and other obviously inapplicable parts) and use Figure 8-1 instead of Figure 5-1. Replace the second paragraph with: Place 100 ml of 80 percent isopropanol in the first impinger, 100 ml of 3 percent hydrogen peroxide in both the second and third impingers; retain a portion of each reagent for use as a blank solution. Place about 200 g of silica gel in the fourth impinger.

NOTE.—If moisture content is to be determined by impinger analysis, weigh each of the first three impingers (plus absorbing solution) to the nearest 0.5 g and record these weights. The weight of the silica gel (or silica gel plus container) must also be determined to the nearest 0.5 g and recorded.

4.1.4 Pretest Leak-Check Procedure. Follow the basic procedure outlined in Method 5, Section 4.1.4.1, noting that the probe heater shall be adjusted to the minimum temperature required to prevent condensation, and also that verbage such as, "* * * plugging the inlet to the filter holder * * *," shall be replaced by, "* * * plugging the inlet to the first impinger * * *." The pretest leak-check is optional.

4.1.5 Train Operation. Follow the basic procedures outlined in Method 5, Section 4.1.5, in conjunction with the following special instructions. Data shall be recorded on a sheet similar to the one in Figure 8-2. The sampling rate shall not exceed 0.030 m³/min (1.0 cfm) during the run. Periodically during the test, observe the connecting line between the probe and first impinger for signs of condensation. If it does occur, adjust the probe heater setting upward to the minimum temperature required to prevent condensation. If component changes become necessary during a run, a leak-check shall be done immediately before each change, according to the procedure outlined in Section 4.1.4.2 of Method 5 (with appropriate modifications, as mentioned in Section 4.1.4 of this method); record all leak rates. If the leakage rate(s) exceed the specified rate, the tester shall either void the run or shall plan to correct the sample volume as outlined in Section 6.3 of Method 5. Immediately after component changes, leak-checks are optional. If these leak-checks are done, the procedure outlined in Section 4.1.4.1 of Method 5 (with appropriate modifications) shall be used.

PLANT _____

LOCATION _____

OPERATOR _____

DATE _____

RUN NO. _____

SAMPLE BOX NO. _____

METER BOX NO. _____

METER ΔH@ _____

C FACTOR _____

PITOT TUBE COEFFICIENT, Cp _____

SCHEMATIC OF STACK CROSS SECTION

STATIC PRESSURE, mm Hg (in. Hg) _____

AMBIENT TEMPERATURE _____

BAROMETRIC PRESSURE _____

ASSUMED MOISTURE, % _____

PROBE LENGTH, m (ft) _____

NOZZLE IDENTIFICATION NO. _____

AVERAGE CALIBRATED NOZZLE DIAMETER, cm (in.) _____

PROBE HEATER SETTING _____

LEAK RATE, m³/min, (cfm) _____

PROBE LINER MATERIAL _____

FILTER NO. _____

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	VACUUM mm Hg (in. Hg)	STACK TEMPERATURE (T_s), °C (°F)	VELOCITY HEAD (ΔP_s), mm H_2O (in. H_2O)	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER, mm H_2O (in. H_2O)	GAS SAMPLE VOLUME, m^3 (ft^3)	GAS SAMPLE TEMPERATURE AT DRY GAS METER		TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °C (°F)
							INLET, °C (°F)	OUTLET, °C (°F)	
TOTAL							Avg	Avg	
AVERAGE							Avg		

Figure 8-2. Field data.

After turning off the pump and recording the final readings at the conclusion of each run, remove the probe from the stack. Conduct a post-test (mandatory) leak-check as in Section 4.1.4.3 of Method 5 (with appropriate modification) and record the leak rate. If the post-test leakage rate exceeds the specified acceptable rate, the tester shall either correct the sample volume, as outlined in Section 6.3 of Method 5, or shall void the run.

Drain the ice bath and, with the probe disconnected, purge the remaining part of the train, by drawing clean ambient air through the system for 15 minutes at the average flow rate used for sampling.

NOTE.—Clean ambient air can be provided by passing air through a charcoal filter. At the option of the tester, ambient air (without cleaning) may be used.

4.1.6 Calculation of Percent Isokinetic. Follow the procedure outlined in Method 5, Section 4.1.6.

4.2 Sample Recovery.

4.2.1 Container No. 1. If a moisture content analysis is to be done, weigh the first impinger plus contents to the nearest 0.5 g and record this weight.

Transfer the contents of the first impinger to a 250-ml graduated cylinder. Rinse the probe, first impinger, all connecting glassware before the filter, and the front half of the filter holder with 80 percent isopropanol. Add the rinse solution to the cylinder. Dilute to 250 ml with 80 percent isopropanol. Add the filter to the solution, mix, and transfer to the storage container. Protect the solution against evaporation. Mark the level of liquid on het container and identify the sample container.

4.2.2 Container No. 2. If a moisture content analysis is to be done, weigh the second and third impingers (plus contents) to the nearest 0.5 g and record these weights. Also, weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g.

Transfer the solutions from the second and third impingers to a 1000-ml graduated cylinder. Rinse all connecting glassware (including back half of filter holder) between the filter and silica gel impinger with deionized, distilled water, and add this rinse water to the cylinder. Dilute to a volume of 1000 ml with deionized, distilled water. Transfer the solution to a storage container. Mark the level of liquid on the container. Seal and identify the sample container.

4.3 Analysis.

Note the level of liquid in containers 1 and 2, and confirm whether or not any sample was lost during shipment; note this on the analytical data sheet. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results.

4.3.1 Container No. 1. Shake the container holding the isopropanol solution and the filter. If the filter breaks up, allow the fragments to settle for a few minutes before removing a sample. Pipette a 100-ml aliquot of this solution into a 250-ml Erlenmeyer flask, add 2 to 4 drops of thorin indicator, and titrate to a pink endpoint using 0.0100 N barium perchlorate. Repeat the titration with a second aliquot of sample and average the titration

values. Replicate titrations must agree within 1 percent or 0.2 ml, whichever is greater.

4.3.2 Container No. 2. Thoroughly mix the solution in the container holding the contents of the second and third impingers. Pipette a 10-ml aliquot of sample into a 250-ml Erlenmeyer flask. Add ml of isopropanol, 2 to 4 drops of thorin indicator, and titrate to a pink endpoint using 0.0100 *N* barium perchlorate. Repeat the titration with a second aliquot of sample and average the titration values. Replicate titrations must agree within 1 percent or 0.2 ml, whichever is greater.

4.3.3 Blanks. Prepare blanks by adding 2 to 4 drops of thorin indicator to 100 ml of 80 percent isopropanol. Titrate the blanks in the same manner as the samples.

5. *Calibration*

5.1 Calibrate equipment using the procedures specified in the following sections of Method 5: Section 5.3 (metering system); Section 5.5 (temperature gauges); Section 5.7 (barometer). Note that the recommended leak-check of the metering system, described in Section 5.6 of Method 5, also applies to this method.

5.2 Standardize the barium perchlorate solution with 25 ml of standard sulfuric acid, to which 100 ml of 100 percent isopropanol has been added.

6. *Calculations*

Note.—Carry out calculations retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

6.1 Nomenclature.

A_n = Cross-sectional area of nozzle, m² (ft²).
B_{ws} = Water vapor in the gas stream, proportion by volume.
$C_{H_2SO_4}$ = Sulfuric acid (including SO_3) concentration, g/dscm (lb/dscf).
C_{SO_2} = Sulfur dioxide concentration, g/dscm (lb/dscf).
I = Percent of isokinetic sampling.
N = Normality of barium perchlorate titrant, g equivalents/liter.
P_{bar} = Barometric pressure at the sampling site, mm Hg (in. Hg).
P_s = Absolute stack gas pressure, mm Hg (in. Hg).
P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).
T_m = Average absolute dry gas meter temperature (see Figure 8-2), ° K (° R).
T_s = Average absolute stack gas temperature (see Figure 8-2), ° K (° R).
T_{std} = Standard absolute temperature, 293° K (528° R).
V_a = Volume of sample aliquot titrated, 100 ml for H_2SO_4 and 10 ml for SO_2.
V_{lc} = Total volume of liquid collected in impingers and silica gel, ml.
V_m = Volume of gas sample as measured by dry gas meter, dcm (dcf).
$V_{m(std)}$ = Volume of gas sample measured by the dry gas meter corrected to standard conditions, dscm (dscf).
v_s = Average stack gas velocity, calculated by Method 2, Equation 2-9, using data obtained from Method 8, m/sec (ft/sec).
V_{soln} = Total volume of solution in which the sulfuric acid or sulfur dioxide sample is contained, 250 ml or 1,000 ml, respectively.
V_t = Volume of barium perchlorate titrant used for the sample, ml.
V_{tb} = Volume of barium perchlorate titrant used for the blank, ml.
Y = Dry gas meter calibration factor.
ΔH = Average pressure drop across orifice meter, mm (in.) H_2O.
θ = Total sampling time, min.
13.6 = Specific gravity of mercury.
60 = sec/min.
100 = Conversion to percent.

6.2 Average dry gas meter temperature and average orifice pressure drop. See data sheet (Figure 8-2).

6.3 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20° C and 760 mm Hg or 68° F and 29.92 in. Hg) by using Equation 8-1.

$$V_{m(std)} = V_m Y \left(\frac{T_{std}}{T_m}\right) \frac{P_{bar} + \left(\frac{\Delta H}{13.6}\right)}{P_{std}}$$

$$= K_1 V_m Y \frac{P_{bar} + (\Delta H/13.6)}{T_m}$$

Equation 8-1

where:
K_1 = 0.3858 °K/mm Hg for metric units.
= 17.64 °R/in. Hg for English units.

NOTE.—If the leak rate observed during any mandatory leak-checks exceeds the specified acceptable rate, the tester shall either correct the value of V_m in Equation 8-1 (as described in Section 6.3 of Method 5), or shall invalidate the test run.

6.4 Volume of Water Vapor and Moisture Content. Calculate the volume of water vapor using Equation 5-2 of Method 5; the weight of water collected in the impingers and silica gel can be directly converted to milliliters (the specific gravity of water is 1 g/ml). Calculate the moisture content of the stack gas, using Equation 5-3 of Method 5. The "Note" in Section 6.5 of Method 5 also applies to this method. Note that if the effluent gas stream can be considered dry, the volume of water vapor and moisture content need not be calculated.

6.5 Sulfuric acid mist (including SO_3) concentration.

$$C_{H_2SO_4} = K_2 \frac{N(V_t - V_{tb})\left(\frac{V_{soln}}{V_a}\right)}{V_{m(std)}}$$

Equation 8-2

where:
K_2 = 0.04904 g/milliequivalent for metric units.
= 1.081×10^{-4} lb/meq for English units.

6.6 Sulfur dioxide concentration.

$$C_{SO_2} = K_2 \frac{N(V_t - V_{tb})\left(\frac{V_{soln}}{V_a}\right)}{V_{m(std)}}$$

Equation 8-3

where:
K_2 = 0.03203 g/meq for metric units.
= 7.061×10^{-4} lb/meq for English units.

6.7 Isokinetic Variation.

6.7.1 Calculation from raw data.

$$I = \frac{100\, T_s [K_4 V_{lc} + (V_m/T_m) P_{bar} + \Delta H/13.6)]}{60\, \theta\, V_s P_s A_n}$$

Equation 8-4

where:
K_4 = 0.003464 mm Hg-m³/ml-°K for metric units.
= 0.002676 in. Hg-ft³/ml-°R for English units.

6.7.2 Calculation from intermediate values.

$$I = \frac{T_s V_{m(std)} P_{std}\, 100}{T_{std} v_s \theta A_n P_s\, 60\,(1 - B_{ws})}$$

$$= K_5 \frac{T_s V_{m(std)}}{P_s v_s A_n \theta (1 - B_{ws})}$$

Equation 8-5

where:
K_5 = 4.320 for metric units.
= 0.09450 for English units.

6.8 Acceptable Results. If 90 percent $\leq I \leq 110$ percent, the results are acceptable. If the results are low in comparison to the standards and I is beyond the acceptable range, the Administrator may opt to accept the results. Use Citation 4 in the Bibliography of Method 5 to make judgments. Otherwise, reject the results and repeat the test.

7. *Bibliography*

1. Atmospheric Emissions from Sulfuric Acid Manufacturing Processes. U.S. DHEW, PHS, Division of Air Pollution. Public Health Service Publication No. 999-AP-13. Cincinnati, Ohio. 1965.

2. Corbett, P. F. The Determination of SO_2 and SO_3 in Flue Gases. Journal of the Institute of Fuel. 24:237-243. 1961.

3. Martin, Robert M. Construction Details of Isokinetic Source Sampling Equipment. Environmental Protection Agency. Research Triangle Park, N.C. Air Pollution Control Office Publication No. APTD-0581. April, 1971.

4. Patton, W. F. and J. A. Brink, Jr. New Equipment and Techniques for Sampling Chemical Process Gases. Journal of Air Pollution Control Association. 13:162. 1963.

5. Rom, J. J. Maintenance, Calibration, and Operation of Isokinetic Source-Sampling Equipment. Office of Air Programs, Environmental Protection Agency. Research Triangle Park, N.C. APTD-0576. March, 1972.

6. Hamil, H. F. and D. E. Camann. Collaborative Study of Method for Determination of Sulfur Dioxide Emissions from Stationary Sources (Fossil Fuel-Fired Steam Generators). Environmental Protection Agency. Research Triangle Park, N.C. EPA-650/4-74-024. December, 1973.

7. Annual Book of ASTM Standards. Part 31; Water, Atmospheric Analysis. pp. 40-42. American Society for Testing and Materials. Philadelphia, Pa. 1974.

* * * * * *

(Secs. 111, 114, 301(a), Clean Air Act, sec. 4(a) of Pub. L. 91-604, 84 Stat. 1683; sec. 4(a) of Pub. L. 91-604, 84 Stat. 1687; sec. 2 of Pub. L. 90-148, 81 Stat. 504 [42 U.S.C. 1857c-6, 1857c-9, 1857g(a)].)

[FR Doc.77-13608 Filed 8-17-77;8:45 am]

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 784-7]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

Delegation of Authority; New Source Review; State of Montana

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This rule will change the address to which reports and applications must be sent by operators of new sources in the State of Montana. The address change is the result of delegation of authority to the State of Montana for New Source Performance Standards (40 CFR Part 60) and National Emissions Standards for Hazardous Air Pollutants (40 CFR Part 61).

ADDRESS: Any questions or comments should be sent to Director, Enforcement Division, Environmental Protection Agency, 1860 Lincoln Street, Denver, Colo. 80295.

FOR FURTHER INFORMATION CONTACT:

Mr. Irwin L. Dickstein, 303-837-3868.

SUPPLEMENTARY INFORMATION: The amendments below institute certain address changes for reports and applications required from operators of new sources. EPA has delegated to the State of Montana authority to review new and modified sources. The delegated authority includes the review under 40 CFR Part 60 for the standards of performance for new stationary sources and review under 40 CFR Part 61 for national emission standards for hazardous air pollutants.

A Notice announcing the delegation of authority is published today in the FEDERAL REGISTER (42 FR. 44573). The amendments provide that all reports, requests, applications, submittals, and communications previously required for the delegated reviews will now be sent to the Montana Department of Health and Environmental Sciences instead of EPA's Region VIII.

The Regional Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on May 18, 1977, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of sections 111 and 112 of the Clean Air Act, as amended, 42 U.S.C. 1857, 1857c-5, 6, 7 and 1857g.

Dated: August 17, 1977.

JOHN A. GREEN,
Regional Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (BB) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(BB) State of Montana, Department of Health and Environmental Services, Cogswell Building, Helena, Mont. 59601.

* * * * *

Part 61 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

2. In § 61.04 paragraph (b) is amended by revising subparagraph (BB) to read as follows:

§ 61.04 Address.

* * * * *

(b) * * *

(BB) State of Montana, Department of Health and Environmental Sciences, Cogswell Building, Helena, Mont. 59601.

[FR Doc.77-25827 Filed 9-2-77;8:45 am]

FEDERAL REGISTER, VOL. 42, NO. 172

TUESDAY, SEPTEMBER 6, 1977

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Applicability Dates; Correction

AGENCY: Environmental Protection Agency.

ACTION: Correction.

SUMMARY: This document corrects the final rule that appeared at page 37935 in the FEDERAL REGISTER of Monday, July 25, 1977 (FR Doc. 77-21230).

EFFECTIVE DATE: September 7, 1977.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone No. 919-541-5271.

Dated: August 31, 1977.

EDWARD F. TUERK,
Acting Assistant Administrator, for Air and Waste Management.

In FR Doc. 77-21230 appearing at page 37935 in the FEDERAL REGISTER of Monday, July 25, 1977, the following corrections are made to §§ 60.250(b) and 60.270 (b) on page 37938:

1. The applicability date in § 60.250(b) is corrected to October 24, 1974.

2. The applicability date in § 60.270(b) is corrected to October 21, 1974.

(Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 1857c-6, 1857g(a)).)

[FR Doc.77-26023 Filed 9-6-77;8:45 am]

FEDERAL REGISTER, VOL. 42, NO. 173

WEDNESDAY, SEPTEMBER 7, 1977

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 790-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State of Wyoming

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This rule will change the address to which reports and applications must be sent by owners and operators of new and modified sources in the State of Wyoming. The address change is the result of delegation of authority to the State of Wyoming for New Source Performance Standards (40 CFR Part 60).

ADDRESS: Any questions or comments should be sent to Director, Enforcement Division, Environmental Protection Agency, 1860 Lincoln Street, Denver, Colo. 80295.

FOR FURTHER INFORMATION CONTACT:

Mr. Irwin L. Dickstein, 303-837-3868.

SUPPLEMENTARY INFORMATION: The amendments below institute certain address changes for reports and applications required from operators of new and modified sources. EPA has delegated to the State of Wyoming authority to review new and modified sources. The delegated authority includes the review under 40 CFR Part 60 for the standards of performance for new stationary sources.

A notice announcing the delegation of authority is published today in the FEDERAL REGISTER (Notices Section). The amendments now provide that all reports, requests, applications, submittals, and communications previously required for the delegated reviews will now be sent to the Air Quality Division of the Wyoming Department of Environmental Quality instead of EPA's Region VIII.

The Regional Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on August 2, 1977, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

(Sec. 111, Clean Air Act, as amended (42 U.S.C. 1857, 1857c-5, 6, 7, 1857g).

Dated: August 25, 1977.

JOHN A. GREEN,
Regional Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraph (ZZ) to read as follows:

§ 60.4 Address.

* * * * * * *

(b) * * *

(ZZ) State of Wyoming, Air Quality Division of the Department of Environmental Quality, Hathaway Building, Cheyenne, Wyo. 82002.

* * * * * * *

[FR Doc.77-26905 Filed 9-14-77;8:45 am]

FEDERAL REGISTER, VOL. 42, NO. 179

THURSDAY, SEPTEMBER 15, 1977

Title 40—Protection of Environment

[FRL 770-7]

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Emission Guideline for Sulfuric Acid Mist

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action establishes emission guidelines and times for compliance for control of sulfuric acid mist emissions from existing sulfuric acid plants. Standards of performance have been issued for emissions of sulfuric acid mist, a designated pollutant, from new, modified, and reconstructed sulfuric acid plants. The Clean Air Act requires States to control emissions of designated pollutants from existing sources, and this rulemaking initiates the States' action and provides them guidelines for what will be acceptable by EPA.

DATES: State plans providing for the control of sulfuric acid mist from existing plants are due for submission to the Administrator on July 18, 1978. The Administrator has four months from the date required for submission of the plans, or until November 18, 1978, to take action to approve or disapprove the plan or portions of it.

ADDRESSES: Copies of the final guideline document are available by writing to the EPA Public Information Center (PM-215), 401 M Street SW., Washington, D.C. 20460. "Final Guidance Document: Control of Sulfuric Acid Mist Emissions From Existing Sulfuric Acid Production Units," June 1977, should be specified when requesting the document. A summary of the comments and EPA's responses may be obtained at the same address. Copies of the comment letters responding to the proposed rulemaking published in the FEDERAL REGISTER on November 4, 1976 (41 FR 48706) are available for public inspection and copying at the U.S. Environmental Protection Agency, Public Information Reference Unit (EPA Library), Room 2922, 401 M Street SW., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711; telephone: 919-541-5271.

SUPPLEMENTARY INFORMATION: On November 4, 1976 (41 FR 48706) EPA proposed an emission guideline for sulfuric acid mist emissions from existing sulfuric acid plants and announced the availability or a draft guideline document for public comment. A discussion of the background and comments received follows:

BACKGROUND

Section 111(d) of the Clean Air Act requires that "designated" pollutants controlled under standards of performance for new stationary sources by section 111(b) of the Act must also be controlled at exsiting sources in the same source category. New source standards of performance for sulfuric acid mist were promulgated December 23, 1971 (36 FR 24876). Sulfuric acid mist is considered a designated pollutant; therefore, it must be controlled under the provisions of section 111(d).

As a step toward implementing the requirements of section 111(d), Subpart B of Part 60, entitled "State Plans for the Control of Certain Pollutants From Existing Facilities," was published on November 17, 1975 (40 FR 53340).

Subpart B provides that once a standard of performance for the control of a designated pollutant from a new source category is promulgated, the Administrator will then publish a draft emission guideline and guideline document applicable to the control of the same pollutant from designated (existing) facilities. For health-related pollutants, the emission guideline will be proposed and subsequently be promulgated while emission guidelines for welfare-related pollutants will appear only in the applicable guideline document. Sulfuric acid mist is considered a health-related pollutant; therefore, the proposed emission guideline and the announcement that the draft guideline document was available for public inspection and comment appeared in the FEDERAL REGISTER November 4, 1976.

Subpart B also provides nine months for the States to develop and submit plans for control of the designated pollutant from the date that the notice of availability of a final guideline is published; thus, the States will have nine months from this date to develop their plans for the control of sulfuric acid mist at designated facilities within the State.

Another provision of Subpart B is that which provides the Administrator the option of either approving or disapproving the State submitted plan or portions of it within four months after the date required for submission. If the plan or a portion of it is disapproved, the Administrator is required to promulgate a new plan or a replacement of the inadequate portions of the plan. These and related provisions of Subpart B are essentially patterned after section 110 of the Act and 40 CFR Part 51 which sets forth the requirements for adoption and submittal of State implementation plans under section 110 of the Act.

COMMENTS AND RESPONSES

During the 60-day comment period following the publication of the proposed emission guidelines on November 4, 1976, eleven comment letters were received; four from State pollution control agencies, five from industry and two from other government agencies. None of the comments warranted a change in the emission guideline nor did any comments justify any significant changes in the guideline document.

One commenter believed that sulfuric acid mist is included within the definition of sulfur oxides as contained in the Air Quality Criteria for Sulfur Oxides; therefore, it is subject to control as a criteria pollutant under State implementation plans, section 110 of the Clean Act, and not as a designated pollutant under section 111(d) of the Act. EPA does not agree with this comment. Sulfuric acid mist is only one of a number of related compounds noted in the criteria document defining sulfur oxides. Sulfuric acid mist is not listed and regulated in and of itself. In addition, although some designated pollutants controlled under section 111(d) may occur in particulate as well as gaseous form and thus may be controlled to some degree under State implementation plan regulations requiring control of particulate matter, specific rather than incidental control of such pollutants is required under section 111(d).

Several commenters were concerned that the emission guideline was not based on the health and welfare effects of sulfuric acid mist or on such other factors as plant site location and the hazard of cumulative impacts where emissions from other sources interacted. Another commenter noted that since the toxicological effects of exposure to sulfuric acid mist are a function of concentration and time, a daily maximum time-weighted average concentration limitation should be considered.

These comments appear to be based on a misunderstanding of the intent and purpose of section 111(d) of the Act. In the preamble to the section 111(d) procedural regulation (40 FR 53340), it is stated that section 111(d) requires emission controls based on the general principle of the application of the best adequately demonstrated control technology, considering costs, rather than controls based directly on health or welfare effects or on other factors such as those mentioned in the comments. Section 111(b)(1)(A) of the Act requires the Administrator to list categories of sources once it is determined that they may contribute to the endangerment of public health or welfare. While this is a prerequisite for the development of standards under section 111(d), the emission guideline is technology-based rather than tied specifically to protection of health or welfare. The States, in developing regulations for the control of sulfuric acid mist, have the prerogative under 40 CFR 60.24 (f) and (g) to develop standards which may be based on health or welfare considerations or on any other relevant factors.

Some of the comments addressed the stringency of the emission guideline. One commenter considered the emission guideline inflexible to the point where its application will be too stringent in some areas and inadequate in others. Another commenter thought the guideline document indicated that facilities using elemental sulfur as feedstock can meet more rigid emission standards and that the

emission guidelines should include more stringent standards for these facilities.

EPA has provided a great deal of flexibility in developing emission standards for the control of designated pollutants under Subpart B of Part 60. Specifically, 40 CFR 60.24(b) provides that nothing under Subpart B precludes any State from adopting or enforcing more stringent emission standards than those specified in the guideline document. On the other hand, 40 CFR Part 60.24(f) provides that States, "on a case-by-case basis for particular designated facilities, or classes of facilities * * * may provide for the application of less stringent emission standards than those otherwise required * * *" provided certain conditions are demonstrated by the State. The conditions include unreasonable cost of control resulting from plant age, location or basic process design, physical impossibility of installing necessary control equipment, and other factors specific to the facility that make the application of a less stringent standard significantly more reasonable. To include more stringent standards for facilities using elemental sulfur as feedstock would cause an unacceptable economic burden for those sources which have already installed efficient emission control equipment to meet a State regulation. To require these sources to retrofit additional emission control equipment to meet a more stringent standard would be inequitable.

MISCELLANEOUS

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Analysis under Executive Order 11821 and 11949 and OMB Circular A-107.

Dated: September 22, 1977.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I of Title 40 of the Code of Federal Regulations is amended by adding Subpart C as follows:

Subpart C—Emission Guidelines and Compliance Times

Sec.
60.30 Scope.
60.31 Definitions
60.32 Designated facilities.
60.33 Emission guidelines.
60.34 Compliance times.

AUTHORITY: Sections 111(d), 301(a) of the Clean Air Act as amended (42 U.S.C. 1857c-6 and 1857g(a)), and additional authority as noted below.

Subpart C—Emission Guidelines and Compliance Times

§ 60.30 Scope.

This subpart contains emission guidelines and compliance times for the control of certain designated pollutants from certain designated facilities in accordance with section 111(d) of the Act and Subpart B.

§ 60.31 Definitions.

Terms used but not defined in this subpart have the meaning given them in the Act and in Subparts A and B of this part.

§ 60.32 Designated facilities.

(a) Sulfuric acid production units. The designated facility to which §§ 60.33 (a) and 60.34(a) apply is each existing "sulfuric acid production unit" as defined in § 60.81(a) of Subpart H.

§ 60.33 Emission guidelines.

(a) Sulfuric acid production units. The emission guideline for designated facilities is 0.25 gram sulfuric acid mist (as measured by Reference Method 8, of Appendix A) per kilogram of sulfuric acid produced (0.5 lb/ton), the production being expressed as 100 percent H_2SO_4.

§ 60.34 Compliance times.

(a) Sulfuric acid production units. Planning, awarding of contracts, and installation of equipment capable of attaining the level of the emission guideline established under § 60.33(a) can be accomplished within 17 months after the effective date of a State emission standard for sulfuric acid mist.

[FR Doc.77-30456 Filed 10-17-77;8:45 am]

FEDERAL REGISTER, VOL. 42, NO. 201

TUESDAY, OCTOBER 18, 1977

74 [FRL 793-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Amendments to General Provisions and Copper Smelter Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This rule clarifies that excess emissions during periods of startup, shutdown, and malfunction are not considered a violation of a standard. This rule also clarifies that excess emissions for no more than 1.5 percent of the time during a quarter will not be considered indicative of a potential violation of the new source performance standard for primary copper smelters provided the affected facility and the air pollution control equipment are maintained and operated consistent with good air pollution control practice.

EFFECTIVE DATE: November 1, 1977.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

SUPPLEMENTARY INFORMATION:

BACKGROUND

EPA promulgated standards of performance for primary copper, zinc and lead smelters on January 15, 1976. On March 5, 1976, Kennecott Copper Corporation filed a petition with the United States Court of Appeals for the District of Columbia Circuit requesting that EPA reconsider the standards for copper smelters. EPA proposed to make two clarifying amendments to the standards, and Kennecott agreed to withdraw its court challenge providing these amendments were made. The amendments being made are in response to the following two issues raised in the Kennecott court appeal:

(1) The standards of performance fail to provide for excessive emissions during periods of startup, shutdown, and malfunction.

(2) The standards of performance prescribe averaging times too short to accommodate the normal fluctuations in sulfur dioxide emissions inherent in smelting operations.

EXCESS EMISSIONS DURING STARTUP, SHUTDOWN AND MALFUNCTION

For all sources covered under 40 CFR Part 60, compliance with numerical emission limits must be determined through performance tests. 40 CFR 60.8(c) exempts periods of startup, shutdown, and malfunction from performance tests. By implication this means compliance with numerical emission limits cannot be determined during periods of startup, shutdown, and malfunction. EPA and Kennecott have agreed that for clarification

purposes this should be specifically stated in the regulation. Therefore, an amendment to this effect is being made in 40 CFR 60.8(c).

This exemption from compliance with numerical emission limits during startup, shutdown and malfunction, however, does not exempt the owner or operator from compliance with the requirements of 40 CFR 60.11(d) which says: "At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions."

AVERAGING TIMES

Kennecott alleged that a six-hour averaging time is not long enough to average out periods of excessive emissions of sulfur dioxide which normally occur at smelters equipped with best control technology. According to Kennecott, the six-hour averaging period simply does not mask emission variations caused by normal fluctuations in gas strengths and volumes.

A performance test to determine compliance with the numerical emission limit included in the standard of performance consists of the arithmetic average of three consecutive six-hour emission tests. EPA's analysis of the emission data presented in the background document ("Background Information for New Source Performance Standards: Primary Copper, Zinc, and Lead Smelters," October 1974) supporting the standards of performance for copper smelters indicates that the possibility of a performance test exceeding the standard of performance under normal conditions is extremely low, less than 0.15 percent. This same analysis, however, indicates that the possibility of emissions averaged over a single six-hour period exceeding the numerical emission limit included in the standard of performance during normal operation is about 1.5 percent. To reconcile this situation with the excess emission reporting requirements, which currently require all six-hour periods in excess of the level of the sulfur dioxide standard to be reported as excess emissions, 40 CFR 60.165 is being amended to provide that if emissions exceed the level of the standard for no more than 1.5 percent of the six-hour averaging periods during a quarter, they will not be considered indicative of potential violation of 40 CFR 60.11(d); i.e., indicative of improper maintenance or operation. This exemption applies, however, only if the owner or operator maintains and operates the affected facility and air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions during these periods. This ensures that the control equipment will be operated and emissions will be minimized during this time. Excess emissions during periods of startup, shutdown, and malfunction are not considered part of the 1.5 percent.

MISCELLANEOUS

The Administrator finds that good cause exists for omitting prior notice and public comment on these amendments and for making them immediately effective because they simply clarify the existing regulations and impose no additional substantive requirements.

NOTE.—The EPA has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Statement under Executive Orders 11821 and 11949, and OMB Circular R-107.

Dated: October 25, 1977.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.8, paragraph (c) is amended to read as follows:

§ 60.8 Performance tests.

* * * * *

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

* * * * *

2. In § 60.165, paragraph (d)(2) is amended to read as follows:

§ 60.165 Monitoring of operations.

* * * * *

(d) * * *

(2) Sulfur dioxide. All six-hour periods during which the average emissions of sulfur dioxide, as measured by the continuous monitoring system installed under § 60.163, exceed the level of the standard. The Administrator will not consider emissions in excess of the level of the standard for less than or equal to 1.5 percent of the six-hour periods during the quarter as indicative of a potential violation of § 60.11(d) provided the affected facility, including air pollution control equipment, is maintained and operated in a manner consistent with good air pollution control practice for minimizing emissions during these periods. Emissions in excess of the level of the standard during periods of startup, shutdown, and malfunction are not to be included within the 1.5 percent.

(Secs. 111, 114, and 301(a) of the Clean Air Act as amended (42 U.S.C. 1857c-6, 1857c-9, 1857g(a)).)

[FR Doc.77-31506 Filed 10-31-77;8:45 am]

FEDERAL REGISTER, VOL. 42, NO. 210

TUESDAY, NOVEMBER 1, 1977

75 [FRL 781-7]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Amendment to Subpart O: Sewage Sludge Incinerators

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This rule revises the applicability of the standard of performance for sewage sludge incinerators to cover any incinerator that burns wastes containing more than 10 percent sewage sludge (dry basis) produced by municipal sewage treatment plants, or charges more than 1000 kg (2205 lb) per day municipal sewage sludge (dry basis). The State of Alaska requested that EPA revise the standard because incinerators small enough to meet the needs of small communities in Alaska and comply with the particulate matter standard are too costly, and land disposal is not feasible in areas with permafrost and high water tables. The intended effect of the revision is to exempt from the standard small incinerators for the combined disposal of municipal wastes and sewage sludge when land disposal, which is normally a cheaper and preferable alternative, is infeasible due to permafrost, high water tables, or other conditions.

DATES: This amendment is effective November 10, 1977, as required by § 111(b)(1)(B) of the Clean Air Act as amended.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: On January 26, 1977 (42 FR 4863), EPA published a proposed amendment to Subpart O of 40 CFR Part 60. An error in that proposal necessitated a correction notice that was published on February 18, 1977 (42 FR 10019). The proposed amendment exempted any sewage sludge incinerator located at a municipal waste treatment plant having a dry sludge capacity below 140 kg/hr (300 lb/hr), and where it would not be feasible to dispose of the sludge by land application or in a sanitary landfill because of freezing conditions. Prompting this amendment was a request by the State of Alaska which noted (1) the limited availability of small sludge incinerators which can meet the particulate matter standard, and (2) the difficulty of using landfills as an alternative means of sewage sludge disposal in some Alaskan communities because of permafrost conditions.

During the comment period on that proposal, four comment letters were received. Copies of these letters and a summary of the comments with EPA's responses are available for public inspection and copying at the EPA Public Information Reference Unit, Room 2922 (EPA Library), 401 M Street SW., Washington, D.C. In addition, copies of the comment summary and Agency responses may be obtained upon written request from the Public Information Center (PM-215), Environmental Protection Agency, 401 M Street SW., Washington, D.C. 20460 (specify Public Comment Summary: Amendment to Standards of performance for Sewage Treatment Plants).

One commenter requested that industrial sludge incineration also be exempted by this revision. Only incinerators which burn sludge produced by municipal sewage treatment plants are covered by Subpart O. Incineration of industrial sludges are not covered because they may involve special metal, toxic and radioactive waste problems which were not addressed by the original study for developing the standard.

Three other commenters questioned the applicability of the proposed amendment. One questioned the need for the proposed exemption, arguing that small incinerators with control devices sufficient to meet the existing particulate emission standard of 0.65 g/kg dry sludge input are commercially available and should be used. Two others recommended wording to broaden the proposed exemption. They suggested that the amendment as proposed is too restrictive, considering the conditions faced by small communities in Alaska. One noted that high water-table levels severely limit land disposal of sludge in many areas. The other made a similar comment but attributed the problems to high rainfall as well.

Based upon these comments, EPA reevaluated the need for the proposed exemption. EPA recognizes that at least one type of incinerator (the fluidized-bed type) can be constructed in size categories of less than 140 kg/hr (300 lb/hr) and with emission control equipment capable of achieving the existing standard. However, separate sludge disposal by an incinerator dedicated exclusively to sewage sludge is unduly costly for a small community. This conclusion is based on data contained in two EPA publications: A Guide to the Selection of Cost-Effective Wastewater Treatment Systems (EPA-430/9-75-002), and Municipal Sludge Management: EPA Construction Grants Program—An Overview of the Sludge Management Situation (EPA-430/9-76-009). Sludge incineration costs, especially those for operation and maintenance, were compared for sewage treatment plants of 1 and 10 million gallons per day (mgd) capacity. Costs for a 1 mgd plant (about 1000 kg of dry sludge per day) were 100 to 300 percent higher than those for a 10 mgd facility. A small, remote community which already incinerates its other municipal wastes would bear the heaviest burden if forced to incinerate its sewage sludge separately.

In most instances, neither municipal waste nor sewage sludge incinerators are constructed because land disposal is a more cost-effective alternative. The co-incineration of sewage sludge with solid waste should be a cost-effective and energy-efficient disposal alternative whenever land disposal options are not reasonably available. Since high water table levels, high annual precipitation, freezing conditions, and other factors limit or preclude the land application or sanitary landfilling of sludge, EPA has decided to broaden the exemption. Only freezing conditions were considered in the proposed exemption. However, an exemption based on these additional factors would be difficult to enforce due to climatic variability.

In order to make the exemption sufficiently broad and readily enforceable, EPA has decided to exempt incinerators that burn not more than 1000 kg per day of sewage sludge from municipal sewage treatment plants provided that the sewage sludge (dry basis) does not comprise, by weight, more than 10 percent of the total waste burned. The exemption provides relief only when sewage sludge is co-incinerated with municipal wastes, since any incinerator combusting more than 10 percent sewage sludge is affected by the emission standard regardless of the amount of sludge combusted. This approach, is based principally on the economics of sewage waste disposal and applies to any small community faced with very difficult land disposal conditions. It allows disposal of small quantities of sewage sludge in incinerators primarily combusting municipal refuse.

Currently, sludge incineration for small communities is 50 to 100 percent more costly per ton of dry sludge than land application or sanitary landfilling. Even though EPA is proposing criteria for landfill design and operation, the costs of incineration are expected to remain significantly higher. Thus, it is expected that this exemption will not cause a shift to incineration, but will only pro-

vide relief in areas where land disposal is either infeasible or very costly.

The purpose of the amendment is to relieve small communities (<9,000 population) of the burden of constructing separate incinerators for municipal wastes and sewage sludge in areas where land disposal is not feasible. Co-incineration of sewage sludge with solid wastes is less costly than separate sludge incineration and provides an energy benefit in lower auxiliary fuel consumption. Without this amendment, any co-incineration facility would have been considered a sludge incinerator under Subpart O.

Since sludge incineration costs decline as the quantities disposed of increase, this amendment limits the exemption to co-incineration units burning not more than 1000 kg (2205 lb) dry sludge per day. At an average generation rate of 0.11 kg (0.25 lb) dry sludge per person per day, the 1000 kg limit represents a population of approximately 9,000 persons. The 10 percent sludge allowance in such co-incineration is based on the fact that an average community generates about 14 times as much solid waste per person as dry sludge. Thus the 10 percent allowance should easily permit a small community to co-incinerate all its sludge and solid waste in one facility.

This amendment does not affect the applicability of the National Emission Standard for Mercury under 40 CFR Part 61. However, significant mercury wastes are usually not found in sewage sludge from small communities, but are more commonly found in metropolitan wastes from industrial activity.

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect emission limits achievable with the best adequately demonstrated systems of emission reduction considering the cost of such systems. State implementation plans (SIPs) approved or promulgated under section 110 of the Act, on the other hand, must provide for the attainment and maintenance of national ambient air quality standards (NAAQS) designed to protect public health and welfare. For that purpose SIPs must in some cases require greater emission reductions than those required by standards of performance for new sources.

States are free under section 116 of the Act to establish even more stringent emission limits than those necessary to attain or maintain the NAAQS under section 110 or those for new sources established under section 111. Thus, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Analysis under Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: November 3, 1977.

DOUGLAS M. COSTLE,
Administrator.

In 40 CFR Part 60, Subpart O is amended by revising § 60.150 and § 60.153 as follows:

§ 60.150 Applicability and designation of affected facility.

(a) The affected facility is each incinerator that combusts wastes containing more than 10 percent sewage sludge (dry basis) produced by municipal sewage treatment plants, or each incinerator that charges more than 1000 kg (2205 lb) per day municipal sewage sludge (dry basis).

(b) Any facility under paragraph (a) of this section that commences construction or modification after June 11, 1973, is subject to the requirements of this subpart.

§ 60.153 Monitoring of operations.

(a) The owner or operator of any sludge incinerator subject to the provisions of this subpart shall:

(1) Install, calibrate, maintain, and operate a flow measuring device which can be used to determine either the mass or volume of sludge charged to the incinerator. The flow measuring device shall have an accuracy of ±5 percent over its operating range.

(2) Provide access to the sludge charged so that a well mixed representative grab sample of the sludge can be obtained.

(3) Install, calibrate, maintain, and operate a weighing device for determining the mass of any municipal solid waste charged to the incinerator when sewage sludge and municipal solid waste are incinerated together. The weighing device shall have an accuracy of ±5 percent over its operating range.

(Sections 111, 114, 301(a) of the Clean Air Act as amended [42 U.S.C. 1857c-6, 1857c-9, 1857g(a)].)

[FR Doc.77-32667 Filed 11-9-77;8:45 am]

76

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 803-8]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Opacity Provisions for Fossil-Fuel-Fired Steam Generators

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This rule revises the format of the opacity standard and establishes reporting requirements for excess emissions of opacity for fossil-fuel-fired steam generators. This action is needed to make the standard and reporting requirements conform to changes in the Reference Method for determining opacity which were promulgated on November 12, 1974, (39 FR 39872). The intended effect is to limit opacity of emissions in order to insure proper operation and maintenance of facilities subject to standards of performance.

EFFECTIVE DATE: This rule is effective on December 5, 1977.

ADDRESSES: A summary of the public comments received on the September 10, 1975 (40 FR 42028), proposed rule with EPA's responses is available for public inspection and copying at the EPA Public Information Reference Unit (EPA Library), room 2922, 401 M Street SW., Washington, D.C. 20460. In addition, copies of the comment summary may be obtained by writing to the EPA Public Information Center (PM-215), Washington, D.C. 20460 (specify: "Public Comment Summary: Steam Generator Opacity Exception (40 FR 42028)").

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone: 919-541-5271.

SUPPLEMENTARY INFORMATION: The standards of performance for fossil-fuel-fired steam generators as promulgated under Subpart D of Part 60 in December 23, 1971, (36 FR 24876) allow emissions up to 20 percent opacity, except 40 percent is allowed for two minutes in any hour. On October 15, 1973, (38 FR 28564) a provision was added to Subpart D which required reporting as excess emissions all hourly periods during which there were three or more one-minute periods when average opacity exceeds 20 percent. Changes to the opacity provisions of Subpart A, General Provisions, and to Reference Method 9, Visual Determination of the Opacity of Emissions from Stationary Sources, were promulgated on November 12, 1974 (39

FR 39872). Among these changes is a requirement that opacity be determined by averaging 24 readings taken at 15-second intervals. Because of this change, the Agency reassessed the opacity standard originally promulgated under Subpart D, and on September 10, 1975, proposed amendments to the opacity standard and reporting requirements. Specifically, these amendments would have deleted the permissible exemption (two minutes per hour of emissions of 40 percent opacity) for gaseous and solid fossil fuels.

The proposed amendment to the opacity provisions was based on a review of available data particularly with respect to the challenge to the opacity standards for coal-fired steam generators (*Essex Chemical Corp. et al.* v. *Ruckelshaus, Appalachian Power Co., et al.* vs. *EPA*, 486 F.2d 427, September 10, 1973). Information available at that time indicated that the two-minute exception allowed under § 60.42(a)(2) was unnecessary for large steam generators fired with solid and gaseous fossil fuels.

Interested parties were invited to submit comments. A total of 10 interested parties, including State agencies, electric utility firms, and industrial firms submitted comments. Following a review of the proposed amendments and consideration of the comments, the amendments have been revised and are being promulgated today.

While no information was submitted to show that the exception is needed for large utility steam generators equipped with conventional "cold side" electrostatic precipitators or with scrubbers or fabric filters, commenters contended that the two-minute exception is needed for industrial boilers and for all units equipped with so-called "hot side" electrostatic precipitators, (i.e., precipitators installed upstream of the air heater where temperatures are 590K to 700K). For industrial boilers in the size range of 73 to 220 MW (250 x 10^6 to 750 x 10^6 BTU per hour) heat input, commenters stated that the frequency of soot blowing would have to be increased significantly over present practices if the exception were deleted. More frequent soot blowing would increase costs and energy requirements considerably without any decrease in particulate emissions. Operators of "hot side" precipitators pointed out that where hot side precipitators are used, soot-blowing opacity exceptions are necessary to allow cleaning of the air heater. They noted that since the air heaters are downstream of "hot side" precipitators, any particulate which is removed by soot-blowing will be released with exhaust gases and will contribute to opacity.

EPA has concluded that for steam generators designed for compliance with the particulate matter standard of performance, there are legitimate reasons for providing a limited exception to the opacity standard, and thus, while the format of the opacity standard is revised, the opacity exemption for coal-fired units is retained. The exception could be deleted for gaseous fossil fuel, but since opacity is not a problem from gas-fired units, there is no need to further complicate the regulation by deleting the exception for gas. The two-minute exception could be deleted for very large coal-fired units (>220 MW heat input) that are not equipped with hot side precipitators, but again the deletion would have little effect and would needlessly complicate the regulation.

Section 60.42(a)(2) is amended by expressing the two-minute 40 percent opacity exception in terms of a six-minute 27 percent average opacity (a weighted average of two minutes at 40 percent opacity and four minutes at 20 percent opacity) for consistency with Reference Method 9. This change does not alter the stringency of the standard. In addition, § 60.45(g)(1) which was reserved on October 6, 1975, (40 FR 46250) pending resolution of the opacity exception, is added to require reporting as excess emissions any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except for the one permissible six-minute period per hour of up to 27 percent opacity.

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Analysis under Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: November 23, 1977.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. Section 60.42(a)(2) is revised as follows:

§ 60.42 Standard for particulate matter.

(a) * * *

(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.

(Sec. 111, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7601).)

2. Section 60.45(g)(1) is added as follows:

§ 60.45 Emission and fuel monitoring.

* * * * *

(g) * * *

(1) *Opacity.* Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(Sec. 111, 114, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7414, 7601).)

[FR Doc.77-34641 Filed 12-2-77;8:45 am]

77

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to the Commonwealth of Puerto Rico

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: A notice announcing EPA's delegation of authority for the New Source Performance Standards to the Commonwealth of Puerto Rico is published at page 62196 of today's FEDERAL REGISTER. In order to reflect this delegation, this document amends EPA regulations to require the submission of all notices, reports, and other communications called for by the delegated regulations to the Commonwealth of Puerto Rico as well as to EPA.

EFFECTIVE DATE: December 9, 1977.

FOR FURTHER INFORMATION CONTACT:

J. Kevin Healy, Attorney, U.S. Environmental Protection Agency, Region II, General Enforcement Branch, Enforcement Division, 26 Federal Plaza, New York, N.Y. 10007, 212-264-1196.

SUPPLEMENTARY INFORMATION: By letter dated January 13, 1977 EPA delegated authority to the Commonwealth of Puerto Rico to implement and enforce the New Source Performance Standards. The Commonwealth accepted this delegation by letter dated October 17, 1977. A full account of the background to this action and of the exact terms of the delegation appears in the Notice of Delegation which is also published in today's FEDERAL REGISTER.

This rulemaking is effective immediately, since the Administrator has found good cause to forgo prior public notice. This addition of the Commonwealth of Puerto Rico address to the Code of Federal Regulations is a technical change and imposes no additional substantive burden on the parties affected.

Dated: November 22, 1977.

ECKARDT C. BECK,
Regional Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

(1) In § 60.4 paragraph (b) is amended by revising subparagraph (BBB) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(AAA) * * *

(BBB)—Commonwealth of Puerto Rico: Commonwealth of Puerto Rico Environmental Quality Board, P.O. Box 11785, Santurce, P.R. 00910.

* * * * *

[FR Doc.77-35162 Filed 12-8-77;8.45 am]

78

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 838-3]

AIR POLLUTION

Delegation of Authority to the State of Minnesota for Prevention of Significant Deterioration; Inspections, Monitoring and Entry; Standards of Performance for New Stationary Sources; and National Emission Standards for Hazardous Air Pollutants

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: The amendment below institutes an address change for the implementation of technical and administrative review and enforcement of Prevention of Significant Deterioration provisions; Inspections, Monitoring and Entry provisions; Standards of Performance for New Stationary Sources; and National Emission Standards for Hazardous Air Pollutants. The notice announcing the delegation of authority is published elsewhere in this issue of the FEDERAL REGISTER.

EFFECTIVE DATE: October 6, 1977.

ADDRESSES: This amendment provides that all reports, requests, applications, and communications required for the delegated authority will no longer be sent to the U.S. Environmental Protection Agency, Region V Office, but will be sent instead to: Minnesota Pollution Control Agency, Division of Air Quality, 1935 West County Road B-2, Roseville, Minn. 55113.

FOR FURTHER INFORMATION, CONTACT:

Joel Morbito, Air Programs Branch, U.S. Environmental Protection Agency, Region V, 230 South Dearborn St., Chicago, Ill. 60604, 312-353-2205.

SUPPLEMENTARY INFORMATION: The Regional Administrator finds good cause for forgoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegations which are granted by this administrative amendment were effective October 6, 1977, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations. This rulemaking is effective immediately and is issued under authority of sections 101, 110, 111, 112, 114, 160-169 of the Clean Air Act, as amended (42 U.S.C. 7401, 7410, 7411, 7412, 7414,-7470-79, 7491). Accordingly, 40 CFR Parts 52, 60 and 61 are amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

Subpart Y—Minnesota

1. Section 52.1224 is amended by adding a new paragraph (b)(5) as follows:

§ 52.1224 General requirements.

* * * * *

(b) * * *

(5) Authority of the Regional Administrator to make available information and data was delegated to the Minnesota Pollution Control Agency effective October 6, 1977.

2. Section 52.1234 is amended by adding a new paragraph (c) as follows:

§ 52.1234 Significant deterioration of air quality.

* * * * *

(c) All applications and other information required pursuant to § 52.21 from sources located in the State of Minnesota shall be submitted to the Minnesota Pollution Control Agency, Division of Air Quality, 1935 West County Road B-2, Roseville, Minn. 55113.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart A—General Provisions

1. Section 60.4 is amended by adding a new paragraph (b)(Y) as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(Y) Minnesota Pollution Control Agency, Division of Air Quality, 1935 West County Road B-2, Roseville, Minn. 55113.

79

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Revision of Reference Method 11

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action revises reference method 11, the method for determining the hydrogen sulfide content of fuel gas streams. The revision is made because EPA found that interferences resulting from the presence of mercaptans in some refinery fuel gases can lead to erroneous test data when the current method is used. This revision eliminates the problem of mercaptan interference and insures the accuracy of the test data.

EFFECTIVE DATE: January 10, 1978.

ADDRESSES: Copies of the comment letters responding to the proposed revision published in the FEDERAL REGISTER on May 23, 1977 (42 FR 26222), and a summary of the comments with EPA's responses are available for public inspection and copying at the U.S. Environmental Protection Agency, Public Information Reference Unit (EPA Library), Room 2922, 401 M Street SW., Washington, D.C. 20460. A copy of the summary of comments and EPA's responses may be obtained by writing the Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711. When requesting this document, "Comments and Responses Summary: Revision of Reference Method 11," should be specified.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Director, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: On March 8, 1974, the Environmental Protection Agency promulgated standards of performance limiting emissions of sulfur dioxide from new, modified, and reconstructed fuel gas combustion devices at petroleum refineries. At the same time, reference method 11 was promulgated as the performance test method for measuring H_2S in the fuel gases. It was found after the promulgation of method 11 that interference resulting from the presence of mercaptans in some refinery fuel gases can lead to erroneous test results in those cases where mercaptans were present in significant concentrations.

Following studies of the problems related to reference method 11, it was decided to revise the method and the revision was proposed in the FEDERAL REGISTER on May 23, 1977. The major change in the proposed revision from the original promulgation was a substitution of a new absorbing solution that is essentially free from mercaptan interference. New sections were also added which described the range and sensitivity, interferences, and precision and accuracy of the revision.

There were seven comments received concerning the proposed revision. Five were received from industry, one from a local environmental control agency and one from a research laboratory. None of the comments warranted any significant changes of the proposed revision. The final revision differs from the revision proposed on May 23, 1977, in only one respect: Phenylarsine oxide standard solution has been included as an acceptable titrant in lieu of sodium thiosulfate.

The effective date of this regulation is January 10, 1978, because section 111(b)(1)(B) of the Clean Air Act provides that standards of performance or revisions of them become effective upon promulgation.

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an economic impact analysis under Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: December 29, 1977.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I of Title 40 of the Code of Federal Regulations is amended by revising Method 11 of Appendix A—Reference Methods as follows:

APPENDIX A.—REFERENCE METHODS

* * * * *

METHOD 11—DETERMINATION OF HYDROGEN SULFIDE CONTENT OF FUEL GAS STREAMS IN PETROLEUM REFINERIES

1. *Principle and applicability.* 1.1 *Principle.* Hydrogen sulfide (H_2S) is collected from a source in a series of midget impingers and absorbed in pH 3.0 cadmium sulfate ($CdSO_4$) solution to form cadmium sulfide (CdS). The latter compound is then measured iodometrically. An impinger containing hydrogen peroxide is included to remove SO_2 as an interfering species. This method is a revision of the H_2S method originally published in the FEDERAL REGISTER, Volume 39, No. 47, dated Friday, March 8, 1974.

1.2 *Applicability.* This method is applicable for the determination of the hydrogen sulfide content of fuel gas streams at petroleum refineries.

2. *Range and sensitivity.* The lower limit of detection is approximately 8 mg/m³ (6 ppm). The maximum of the range is 740 mg/m³ (520 ppm).

3. *Interferences.* Any compound that reduces iodine or oxidizes iodide ion will interfere in this procedure, provide it is collected in the cadmium sulfate impingers. Sulfur dioxide in concentrations of up to 2,600 mg/m³ is eliminated by the hydrogen peroxide solution. Thiols precipitate with hydrogen sulfide. In the absence of H_2S, only co-traces of thiols are collected. When methane- and ethane-thiols at a total level of 300 mg/m³ are present in addition to H_2S, the results vary from 2 percent low at an H_2S concentration of 400 mg/m³ to 14 percent high at an H_2S concentration of 100 mg/m³. Carbon oxysulfide at a concentration of 20 percent does not interfere. Certain carbonyl-containing compounds react with iodine and produce recurring end points. However, acetaldehyde and acetone at concentrations of 1 and 3 percent, respectively, do not interfere.

Entrained hydrogen peroxide produces a negative interference equivalent to 100 percent of that of an equimolar quantity of hydrogen sulfide. Avoid the ejection of hydrogen peroxide into the cadmium sulfate impingers.

4. *Precision and accuracy.* Collaborative testing has shown the within-laboratory coefficient of variation to be 2.2 percent and the overall coefficient of variation to be 5 percent. The method bias was shown to be −4.8 percent when only H_2S was present. In the presence of the interferences cited in section 3, the bias was positive at low H_2S concentrations and negative at higher concentrations. At 230 mg H_2S/m³, the level of the compliance standard, the bias was +2.7 percent. Thiols had no effect on the precision.

5. *Apparatus.*

5.1 Sampling apparatus.

5.1.1 *Sampling line. Six to 7 mm (¼ in.)* Teflon[1] tubing to connect the sampling train to the sampling valve.

5.1.2 Impingers. Five midget impingers, each with 30 ml capacity. The internal diameter of the impinger tip must be 1 mm ±0.05 mm. The impinger tip must be positioned 4 to 6 mm from the bottom of the impinger.

5.1.3 Glass or Teflon connecting tubing for the impingers.

5.1.4 *Ice bath container. To maintain* absorbing solution at a low temperature.

5.1.5 Drying tube. Tube packed with 6- to 16-mesh indicating-type silica gel, or equivalent, to dry the gas sample and protect the meter and pump. If the silica gel has been used previously, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to approval of the Administrator.

NOTE.—Do not use more than 30 g of silica gel. Silica gel absorbs gases such as propane from the fuel gas stream, and use of excessive amounts of silica gel could result in errors in the determination of sample volume.

5.1.6 Sampling valve. Needle valve or equivalent to adjust gas flow rate. Stainless steel or other corrosion-resistant material.

5.1.7 Volume meter. Dry gas meter, sufficiently accurate to measure the sample volume within 2 percent, calibrated at the selected flow rate (~1.0 liter/min) and conditions actually encountered during sampling. *The meter shall be equipped with a* temperature gauge (dial thermometer or equivalent) capable of measuring temperature to within 3° C (5.4° F). The gas meter should have a petcock, or equivalent, on the outlet connector which can be closed during the leak check. Gas volume for one revolution of the meter must not be more than 10 liters.

[1] Mention of trade names of specific products does not constitute endorsement by the Environmental Protection Agency.

5.1.8 Flow meter. Rotameter or equivalent, to measure flow rates in the range from 0.5 to 2 liters/min (1 to 4 cfh).

5.1.9 Graduated cylinder, 25 ml size.

5.1.10 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby National Weather Service station, in which case, the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and the sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice-versa for elevation decrease.

5.1.11 U-tube manometer. 0-30 cm water column. For leak check procedure.

5.1.12 Rubber squeeze bulb. To pressurize train for leak check.

5.1.13 Tee, pinchclamp, and connecting tubing. For leak check.

5.1.14 Pump. Diaphragm pump, or equivalent. Insert a small surge tank between the pump and rate meter to eliminate the pulsation effect of the diaphragm pump on the rotameter. The pump is used for the air purge at the end of the sample run; the pump is not ordinarily used during sampling, because fuel gas streams are usually sufficiently pressurized to force sample gas through the train at the required flow rate. The pump need not be leak-free unless it is used for sampling.

5.1.15 Needle valve or critical orifice. To set air purge flow to 1 liter/min.

5.1.16 Tube packed with active carbon. To filter air during purge.

5.1.17 Volumetric flask. One 1,000 ml.

5.1.18 Volumetric pipette. One 15 ml.

5.1.19 Pressure-reduction regulator. Depending on the sampling stream pressure, a pressure-reduction regulator may be needed to reduce the pressure of the gas stream entering the Teflon sample line to a safe level.

5.1.20 Cold trap. If condensed water or amine is present in the sample stream, a corrosion-resistant cold trap shall be used immediately after the sample tap. The trap shall not be operated below 0° C (32° F) to avoid condensation of C_3 or C_4 hydrocarbons.

5.2 Sample recovery.

5.2.1 Sample container. Iodine flask, glass-stoppered: 500 ml size.

5.2.2 Pipette. 50 ml volumetric type.

5.2.3 Graduated cylinders. One each 25 and 250 ml.

5.2.4 Flasks. 125 ml, Erlenmeyer.

5.2.5 Wash bottle.

5.2.6 Volumetric flasks. Three 1,000 ml.

5.3 Analysis.

5.3.1 Flask. 500 ml glass-stoppered iodine flask.

5.3.2 Burette. 50 ml.

5.3.3 Flask. 125 ml, Erlenmeyer.

5.3.4 Pipettes, volumetric. One 25 ml; two each 50 and 100 ml.

5.3.5 Volumetric flasks. One 1,000 ml; two 500 ml.

5.3.6 Graduated cylinders. One each 10 and 100 ml.

6. *Reagents.* Unless otherwise indicated, it is intended that all reagents conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society, where such specifications are available. Otherwise, use best available grade.

6.1 Sampling.

6.1.1 Cadmium sulfate absorbing solution. Dissolve 41 g of $3CdSO_4 \cdot 8H_2O$ and 15 ml of 0.1 M sulfuric acid in a 1-liter volumetric flask that contains approximately ¾ liter of deionized distilled water. Dilute to volume with deionized water. Mix thoroughly. pH should be 3±0.1. Add 10 drops of Dow-Corning Antifoam B. Shake well before use. If Antifoam B is not used, the alternate acidified iodine extraction procedure (section 7.2.2) must be used.

6.1.2 Hydrogen peroxide, 3 percent. Dilute 30 percent hydrogen peroxide to 3 percent as needed. Prepare fresh daily.

6.1.3 Water. Deionized, distilled to conform to ASTM specifications D1193-72, Type 3. At the option of the analyst, the $KMnO_4$ test for oxidizable organic matter may be omitted when high concentrations of organic matter are not expected to be present.

6.2 Sample recovery.

6.2.1 Hydrochloric acid solution (HCl), 3M. Add 240 ml of concentrated HCl (specific gravity 1.19) to 500 ml of deionized, distilled water in a 1-liter volumetric flask. Dilute to 1 liter with deionized water. Mix thoroughly.

6.2.2 Iodine solution 0.1 N. Dissolve 24 g of potassium iodide (KI) in 30 ml of deionized, distilled water. Add 12.7 g of resublimed iodine (I_2) to the potassium iodide solution. Shake the mixture until the iodine is completely dissolved. If possible, let the solution stand overnight in the dark. Slowly dilute the solution to 1 liter with deionized, distilled water, with swirling. Filter the solution if it is cloudy. Store solution in a brown-glass reagent bottle.

6.2.3 Standard iodine solution, 0.01 N. Pipette 100.0 ml of the 0.1 N iodine solution into a 1-liter volumetric flask and dilute to volume with deionized, distilled water. Standardize daily as in section 8.1.1. This solution must be protected from light. Reagent bottles and flasks must be kept tightly stoppered.

6.3 Analysis.

6.3.1 Sodium thiosulfate solution, standard 0.1 N. Dissolve 24.8 g of sodium thiosulfate pentahydrate ($Na_2S_2O_3 \cdot 5H_2O$) or 15.8 g of anhydrous sodium thiosulfate ($Na_2S_2O_3$) in 1 liter of deionized, distilled water and add 0.01 g of anhydrous sodium carbonate (Na_2CO_3) and 0.4 ml of chloroform ($CHCl_3$) to stabilize. Mix thoroughly by shaking or by aerating with nitrogen for approximately 15 minutes and store in a glass-stoppered, reagent bottle. Standardize as in section 8.1.2.

6.3.2 Sodium thiosulfate solution, standard 0.01 N. Pipette 50.0 ml of the standard 0.1 N thiosulfate solution into a volumetric flask and dilute to 500 ml with distilled water.

NOTE.—A 0.01 N phenylarsine oxide solution may be prepared instead of 0.01 N thiosulfate (see section 6.3.3).

6.3.3 Phenylarsine oxide solution, standard 0.01 N. Dissolve 1.80 g of phenylarsine oxide (C_6H_5AsO) in 150 ml of 0.3 N sodium hydroxide. After settling, decant 140 ml of this solution into 800 ml of distilled water. Bring the solution to pH 6-7 with 6N hydrochloric acid and dilute to 1 liter. Standardize as in section 8.1.3.

6.3.4 Starch indicator solution. Suspend 10 g of soluble starch in 100 ml of deionized, distilled water and add 15 g of potassium hydroxide (KOH) pellets. Stir until dissolved, dilute with 900 ml of deionized distilled water and let stand for 1 hour. Neutralize the alkali with concentrated hydrochloric acid, using an indicator paper similar to Alkacid test ribbon, then add 2 ml of glacial acetic acid as a preservative.

NOTE.—Test starch indicator solution for decomposition by titrating, with 0.01 N iodine solution, 4 ml of starch solution in 200 ml of distilled water that contains 1 g potassium iodide. If more than 4 drops of the 0.01 N iodine solution are required to obtain the blue color, a fresh solution must be prepared.

7. *Procedure.*

7.1 Sampling.

7.1.1 Assemble the sampling train as shown in figure 11-1, connecting the five midget impingers in series. Place 15 ml of 3 percent hydrogen peroxide solution in the first impinger. Leave the second impinger empty. Place 15 ml of the cadmium sulfate absorbing solution in the third, fourth, and fifth impingers. Place the impinger assembly in an ice bath container and place crushed ice around the impingers. Add more ice during the run, if needed.

7.1.2 Connect the rubber bulb and manometer to first impinger, as shown in figure 11-1. Close the petcock on the dry gas meter outlet. Pressurize the train to 25-cm water pressure with the bulb and close off tubing connected to rubber bulb. The train must hold a 25-cm water pressure with not more than a 1-cm drop in pressure in a 1-minute interval. Stopcock grease is acceptable for sealing ground glass joints.

NOTE.—This leak check procedure is optional at the beginning of the sample run, but is mandatory at the conclusion. Note also that if the pump is used for sampling, it is recommended (but not required) that the pump be leak-checked separately, using a method consistent with the leak-check procedure for diaphragm pumps outlined in section 4.1.2 of reference method 6, 40 CFR Part 60, Appendix A.

7.1.3 Purge the connecting line between the sampling valve and first impinger, by disconnecting the line from the first impinger, opening the sampling valve, and allowing process gas to flow through the line for a minute or two. Then, close the sampling valve and reconnect the line to the impinger train. Open the petcock on the dry gas meter outlet. Record the initial dry gas meter reading.

7.1.4 Open the sampling valve and then adjust the valve to obtain a rate of approximately 1 liter/min. Maintain a constant (±10 percent) flow rate during the test. Record the meter temperature.

7.1.5 Sample for at least 10 min. At the end of the sampling time, close the sampling valve and record the final volume and temperature readings. Conduct a leak check as described in Section 7.1.2 above.

7.1.6 Disconnect the impinger train from the sampling line. Connect the charcoal tube and the pump, as shown in figure 11-1. Purge the train (at a rate of 1 liter/min) with clean ambient air for 15 minutes to ensure that all H_2S is removed from the hydrogen peroxide. For sample recovery, cap the open ends and remove the impinger train to a clean area that is away from sources of heat. The area should be well lighted, but not exposed to direct sunlight.

7.2 Sample recovery.

7.2.1 Discard the contents of the hydrogen peroxide impinger. Carefully rinse the contents of the third, fourth, and fifth impingers into a 500 ml iodine flask.

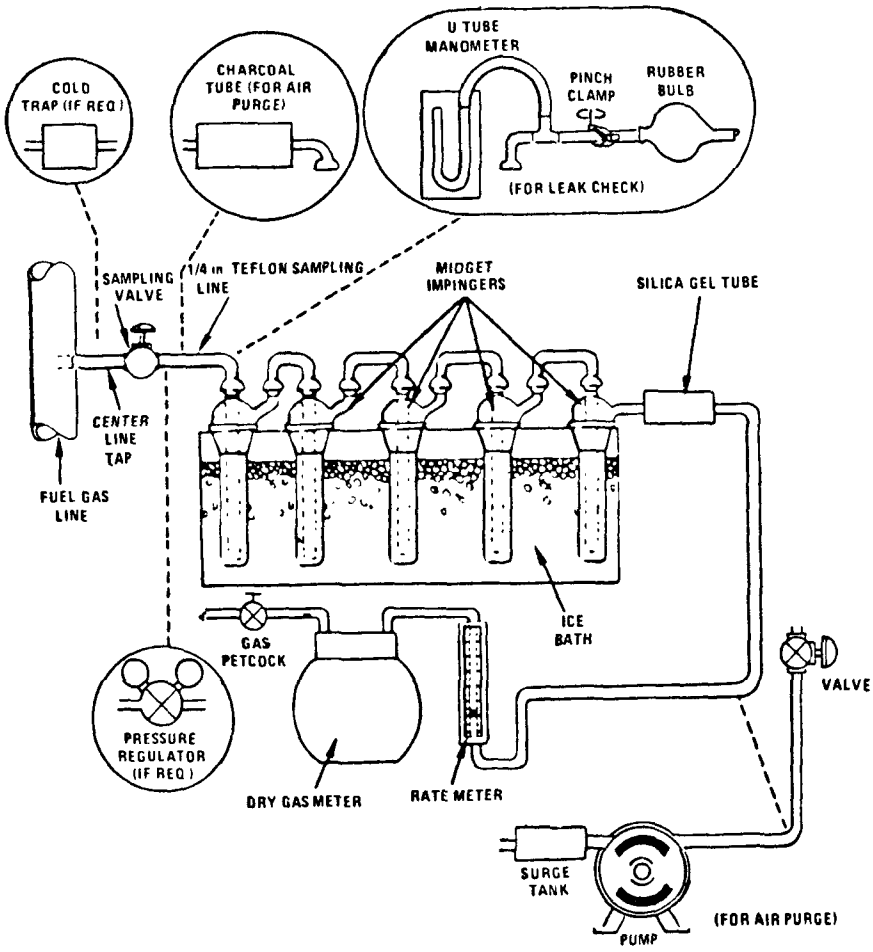


Figure 11-1. H_2S sampling train.

NOTE.—The impingers normally have only a thin film of cadmium sulfide remaining after a water rinse. If Antifoam B was not used or if significant quantities of yellow cadmium sulfide remain in the impingers, the alternate recovery procedure described below must be used.

7.2.2 Pipette exactly 50 ml of 0.01 N iodine solution into a 125 ml Erlenmeyer flask. Add 10 ml of 3 M HCl to the solution. Quantitatively rinse the acidified iodine into the iodine flask. Stopper the flask immediately and shake briefly.

7.2.2 (Alternate). Extract the remaining cadmium sulfide from the third, fourth, and fifth impingers using the acidified iodine solution. Immediately after pouring the acidified iodine into an impinger, stopper it and shake for a few moments, then transfer the liquid to the iodine flask. Do not transfer any rinse portion from one impinger to another; transfer it directly to the iodine flask. Once the acidified iodine solution has been poured into any glassware containing cadmium sulfide, the container must be tightly stoppered at all times except when adding more solution, and this must be done as quickly and carefully as possible. After adding any acidified iodine solution to the iodine flask, allow a few minutes for absorption of the H_2S before adding any further rinses. Repeat the iodine extraction until all cadmium sulfide is removed from the impingers. Extract that part of the connecting glassware that contains visible cadmium sulfide.

Quantitatively rinse all of the iodine from the impingers, connectors, and the beaker into the iodine flask using deionized, distilled water. Stopper the flask and shake briefly.

7.2.3 Allow the iodine flask to stand about 30 minutes in the dark for absorption of the H_2S into the iodine, then complete the titration analysis as in section 7.3.

NOTE.—Caution! Iodine evaporates from acidified iodine solutions. Samples to which acidified iodine have been added may not be stored, but must be analyzed in the time schedule stated in section 7.2.3.

7.2.4 Prepare a blank by adding 45 ml of cadmium sulfate absorbing solution to an iodine flask. Pipette exactly 50 ml of 0.01 N iodine solution into a 125-ml Erlenmeyer flask. Add 10 ml of 3 M HCl. Follow the same impinger extracting and quantitative rinsing procedure carried out in sample analysis. Stopper the flask, shake briefly, let stand 30 minutes in the dark, and titrate with the samples.

NOTE.—The blank must be handled by exactly the same procedure as that used for the samples.

7.3 Analysis.

NOTE.—Titration analyses should be conducted at the sample-cleanup area in order to prevent loss of iodine from the sample. Titration should never be made in direct sunlight.

7.3.1 Using 0.01 N sodium thiosulfate solution (or 0.01 N phenylarsine oxide, if applicable), rapidly titrate each sample in an iodine flask using gentle mixing, until solution is light yellow. Add 4 ml of starch indicator solution and continue titrating slowly until the blue color just disappears. Record V_{TT}, the volume of sodium thiosulfate solution used, or V_{AT}, the volume of phenylarsine oxide solution used (ml).

7.3.2 Titrate the blanks in the same manner as the samples. Run blanks each day until replicate values agree within 0.05 ml. Average the replicate titration values which agree within 0.05 ml.

8. *Calibration and standards.*

8.1 Standardizations.

8.1.1 Standardize the 0.01 N iodine solution daily as follows: Pipette 25 ml of the iodine solution into a 125 ml Erlenmeyer flask. Add 2 ml of 3 M HCl. Titrate rapidly with standard 0.01 N thiosulfate solution or with 0.01 N phenylarsine oxide until the solution is light yellow, using gentle mixing. Add four drops of starch indicator solution and continue titrating slowly until the blue color just disappears. Record V_T, the volume of thiosulfate solution used, or V_{AS}, the volume of phenylarsine oxide solution used (ml). Repeat until replicate values agree within 0.05 ml. Average the replicate titration values which agree within 0.05 ml and calculate the exact normality of the iodine solution using equation 9.3. Repeat the standardization daily.

8.1.2 Standardize the 0.1 N thiosulfate solution as follows: Oven-dry potassium dichromate ($K_2Cr_2O_7$) at 180 to 200° C (360 to 390° F). Weigh to the nearest milligram, 2 g of potassium dichromate. Transfer the dichromate to a 500 ml volumetric flask, dissolve in deionized, distilled water and dilute to exactly 500 ml. In a 500 ml iodine flask, dissolve approximately 3 g of potassium iodide (KI) in 45 ml of deionized, distilled water, then add 10 ml of 3 M hydrochloric acid solution. Pipette 50 ml of the dichromate solution into this mixture. Gently swirl the solution once and allow it to stand in the dark for 5 minutes. Dilute the solution with 100 to 200 ml of deionized distilled water, washing down the sides of the flask with part of the water. Titrate with 0.1 N thiosulfate until the solution is light yellow. Add 4 ml of starch indicator and continue titrating slowly to a green end point. Record V_s, the volume of thiosulfate solution used (ml). Repeat until replicate analyses agree within 0.05 ml. Calculate the normality using equation 9.1. Repeat the standardization each week, or after each test series, whichever time is shorter.

8.1.3 Standardize the 0.01 N Phenylarsine oxide (if applicable) as follows: oven dry potassium dichromate ($K_2Cr_2O_7$) at 180 to 200° C (360 to 390° F). Weigh to the nearest milligram, 2 g of the $K_2Cr_2O_7$; transfer the dichromate to a 500 ml volumetric flask, dissolve in deionized, distilled water, and dilute to exactly 500 ml. In a 500 ml iodine flask, dissolve approximately 0.3 g of potassium iodide (KI) in 45 ml of deionized, distilled water; add 10 ml of 3M hydrochloric acid. Pipette 5 ml of the $K_2Cr_2O_7$ solution into the iodine flask. Gently swirl the contents of the flask once and allow to stand in the dark for 5 minutes. Dilute the solution with 100 to 200 ml of deionized, distilled water, washing down the sides of the flask with part of the water. Titrate with 0.01 N phenylarsine oxide until the solution is light yellow. Add 4 ml of starch indicator and continue titrating slowly to a green end point. Record V_A, the volume of phenylarsine oxide used (ml). Repeat until replicate analyses agree within 0.05 ml. Calculate the normality using equation 9.2. Repeat the standardization each week or after each test series, whichever time is shorter.

8.2 Sampling train calibration. Calibrate the sampling train components as follows:

8.2.1 Dry gas meter.

8.2.1.1 Initial calibration. The dry gas meter shall be calibrated before its initial use in the field. Proceed as follows: First, assemble the following components in series: Drying tube, needle valve, pump, rotameter, and dry gas meter. Then, leak-check the system as follows: Place a vacuum gauge (at least 760 mm Hg) at the inlet to the drying tube and pull a vacuum of 250 mm (10 in.) Hg; plug or pinch off the outlet of the flow meter, and then turn off the pump. The vacuum shall remain stable for at least 30 seconds. Carefully release the vacuum gauge before releasing the flow meter end.

Next, calibrate the dry gas meter (at the sampling flow rate specified by the method) as follows: Connect an appropriately sized wet test meter (e.g., 1 liter per revolution) to the inlet of the drying tube. Make three independent calibration runs, using at least five revolutions of the dry gas meter per run. Calculate the calibration factor, Y (wet test meter calibration volume divided by the dry gas meter volume, both volumes adjusted to the same reference temperature and pressure), for each run, and average the results. If any Y value deviates by more than 2 percent from the average, the dry gas meter is unacceptable for use. Otherwise, use the average as the calibration factor for subsequent test runs.

8.2.1.2 Post-test calibration check. After each field test series, conduct a calibration check as in section 8.2.1.1. above, except for the following variations: (a) The leak check is not to be conducted, (b) three or more revolutions of the dry gas meter may be used, and (3) only two independent runs need be made. If the calibration factor does not deviate by more than 5 percent from the initial calibration factor (determined in section 8.2.1.1.), then the dry gas meter volumes obtained during the test series are acceptable. If the calibration factor deviates by more than 5 percent, recalibrate the dry gas meter as in section 8.2.1.1, and for the calculations, use the calibration factor (initial or recalibration) that yields the lower gas volume for each test run.

8.2.2 Thermometers. Calibrate against mercury-in-glass thermometers.

8.2.3 Rotameter. The rotameter need not be calibrated, but should be cleaned and maintained according to the manufacturer's instruction.

8.2.4 Barometer. Calibrate against a mercury barometer.

9. *Calculations.* Carry out calculations retaining at least one extra decimal figure beyond that of the acquired data. Round off results only after the final calculation.

9.1 Normality of the Standard (~0.1 N) Thiosulfate Solution.

$$N_s = 2.039W/V_s$$

where:

W = Weight of $K_2Cr_2O_7$ used, g.
V_s = Volume of $Na_2S_2O_3$ solution used, ml.
N_s = Normality of standard thiosulfate solution, g-eq/liter.
2.039 = Conversion factor

(6 eq. I_2/mole $K_2Cr_2O_7$) (1,000 ml/liter)/= (294.2 g $K_2Cr_2O_7$/mole) (10 aliquot factor)

9.2 Normality of Standard Phenylarsine Oxide Solution (if applicable).

$$N_A = 0.2039\ W/V_A$$

where:

W = Weight of $K_2Cr_2O_7$ used, g.
V_A = Volume of $C_6H_5A_sO$ used, ml.
N_A = Normality of standard phenylarsine oxide solution, g = eq/liter.
0.2039 = Conversion factor

(6 eq. I_2/mole $K_2Cr_2O_7$) (1,000 ml/liter)/ (249.2 g $K_2Cr_2O_7$/mole) (100 aliquot factor)

9.3 Normality of Standard Iodine Solution.

$$N_I = N_T V_T / V_I$$

where:

N_I = Normality of standard iodine solution, g-eq/liter.
V_I = Volume of standard iodine solution used, ml.
N_T = Normality of standard (~0.01 N) thiosulfate solution; assumed to be 0.1 N_s, g-eq/liter.
V_T = Volume of thiosulfate solution used, ml.

NOTE.—If phenylarsine oxide is used intead of thiosulfate, replace N_T and V_T in Equation 9.3 with N_A and V_{AS}, respectively (see sections 8.1.1 and 8.1.3).

9.4 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20° C) and 760 mm Hg.

$$V_{m(std)} = V_m Y\ [(T_{std}/T_m)\ (P_{bar}/P_{std})]$$

where:

$V_{m(std)}$ = Volume at standard conditions of gas sample through the dry gas meter, standard liters.
V_m = Volume of gas sample through the dry gas meter (meter conditions), liters.
T_{std} = Absolute temperature at standard conditions, 293° K.
T_m = Average dry gas meter temperature, °K.
P_{bar} = Barometric pressure at the sampling site, mm Hg.
P_{std} = Absolute pressure at standard conditions, 760 mm Hg.
Y = Dry gas meter calibration factor.

9.5 Concentration of H_2S. Calculate the concentration of H_2S in the gas stream at standard conditions using the following equation:

$$C_{H_2S} = K[(V_{IT}N_I - V_{TT}N_T)\ \text{sample} - (V_{IT}N_I - V_{TT}N_T)\ \text{blank}]/V_{m(std)}$$

where (metric units):

C_{H_2S} = Concentration of H_2S at standard conditions, mg/dscm.
K = Conversion factor = 17.04×10^3

(34.07 g/mole H_2S) (1,000 liters/m^3) (1,000 mg/g)/ = (1,000 ml/liter) (2 H_2S eq/mole)

V_{IT} = Volume of standard iodine solution = 50.0 ml.
N_I = Normality of standard iodine solution, g-eq/liter.
V_{TT} = Volume of standard (~0.01 N) sodium thiosulfate solution, ml.
N_T = Normality of standard sodium thiosulfate solution, g-eq/liter.
$V_{m(std)}$ = Dry gas volume at standard conditions, liters.

NOTE.—If phenylarsine oxide is used instead of thiosulfate, replace N_T and V_{TT} in Equation 9.5 with N_A and V_{AT}, respectively (see Sections 7.3.1 and 8.1.3).

10. *Stability.* The absorbing solution is stable for at least 1 month. Sample recovery and analysis should begin within 1 hour of sampling to minimize oxidation of the acidified cadmium sulfide. Once iodine has been added to the sample, the remainder of the analysis procedure must be completed according to sections 7.2.2 through 7.3.2.

11. *Bibliography.*

11.1 Determination of Hydrogen Sulfide, Ammoniacal Cadmium Chloride Method. API Method 772-54. In: Manual on Disposal of Refinery Wastes, Vol. V: Sampling and Analysis of Waste Gases and Particulate Matter, American Petroleum Institute, Washington, D.C., 1954.

11.2 Tentative Method of Determination of Hydrogen Sulfide and Mercaptan Sulfur in Natural Gas, Natural Gas Processors Association, Tulsa, Okla., NGPA Publication No. 2265-65, 1965.

11.3 Knoll, J. E., and M. R. Midgett. Determination of Hydrogen Sulfide in Refinery Fuel Gases, Environmental Monitoring Series, Office of Research and Development, USEPA, Research Triangle Park, N.C. 27711, EPA 600/4-77-007.

11.4 Schelll, G. W., and M. C. Sharp. Standardization of Method 11 at a Petroleum Refinery, Midwest Research Institute Draft Report for USEPA, Office of Research and Development, Research Triangle Park, N.C. 27711, EPA Contract No. 68-02-1098, August 1976, EPA 600/4-77-088a (Volume 1) and EPA 600/4-77-088b (Volume 2).

(Secs. 111, 114, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7414, 7601).)

[FR Doc. 78-482 Filed 1-9-78; 8:45 am]

FEDERAL REGISTER, VOL. 43, NO. 6
TUESDAY, JANUARY 10, 1978

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 846-7]

NEW SOURCE REVIEW

Delegation of Authority to the Commonwealth of Kentucky

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: The amendments below institute certain address changes for reports and applications required from operators of new sources. EPA has delegated to the Commonwealth of Kentucky authority to review new and modified sources. The delegated authority includes the reviews under 40 CFR Part 52 for the prevention of significant deterioration. It also includes the review under 40 CFR Part 60 for the standards of performance for new stationary sources and reviewed under 40 CFR Part 61 for national emission standards for hazardous air pollutants. A notice announcing the delegation of authority was published in the Notices section of a previous issue of the FEDERAL REGISTER. These amendments provide that all reports, requests, applications, submittals, and communications previously required for the delegated reviews will now be sent to the Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, West Frankfort Office Complex, U.S. 127, Frankfort, Ky. 40601, instead of EPA's Region IV.

EFFECTIVE DATE: January 25, 1978.

FOR FURTHER INFORMATION, CONTACT:

John Eagles, Air Programs Branch, Environmental Protection Agency, Region IV, 345 Courtland Street NE., Atlanta, Ga. 30308, phone 404-881-2864.

SUPPLEMENTARY INFORMATION: The Regional Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on April 12, 1977, and it serves no purpose to delay the technical change of this addition of the state address to the Code of Federal Regulations.

(Secs. 101, 110, 111, 112, 301, Clean Air Act, as amended, (42 U.S.C. 7401, 7410, 7411, 7412, 7601).)

Dated: January 10, 1978.

JOHN C. WHITE,
Regional Administrator.

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

Part 52 of Chapter I, Title 40, Code of Federal Regulations, is amended as follows:

Subpart S—Kentucky

1. Section 52.920(c) is amended by adding a new paragraph (c)(11) as follows:

§ 52.920 Identification of plan.

* * * * *

(c) * * *

(11) Letters requesting delegation of Federal authority for the administrative and technical portions of the Prevention of Significant Deterioration program were submitted on May 5 and July 13, 1976 by the Secretary of the Department for Natural Resources and Environmental Protection.

2. Section 52.931 is amended by adding a new paragraph (c) as follows:

§ 52.931 Significant deterioration of air quality.

* * * * *

(c) All applications and other information required pursuant to § 52.21 from sources located in the Commonwealth of Kentucky shall be submitted to the Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, West Frankfort Office Complex, U.S. 127, Frankfort, Ky. 40601, instead of the EPA Region IV office.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Part 60 of Chapter I, Title 40, Code of Federal Regulations, is amended as follows:

3. In § 60.4, paragraph (b)(S) is added as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(S) Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, U.S. 127, Frankfort, Ky. 40601.

* * * * *

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

Part 61 of Chapter I, Title 40, Code of Federal Regulations, is amended as follows:

4. In § 61.04, paragraph (b)(S) is added as follows:

§ 61.04 Address.

* * * * *

(b) * * *

(S) Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, U.S. 127, Frankfort, Ky. 40601.

* * * * *

[FR Doc. 78-2032 Filed 1-24-78; 8:45 am]

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 856-1]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State of Delaware

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This document amends regulations concerning air programs to reflect delegation to the State of Delaware of authority to implement and enforce certain Standards of Performance for New Stationary Sources.

EFFECTIVE DATE: February 16, 1978.

FOR FURTHER INFORMATION CONTACT:

Stephen R. Wassersug, Director, Enforcement Division, Environmental Protection Agency, Region III, 6th and Walnut Streets, Philadelphia, Pa. 19106, 215-597-4171.

SUPPLEMENTARY INFORMATION:

I. Background

On September 7, 1977, the State of Delaware requested delegation of authority to implement and enforce certain Standards of Performance for New Stationary Sources. The request was reviewed and on September 30, 1977 a letter was sent to Pierre S. DuPont IV, Governor, State of Delaware, approving the delegation and outlining its conditions. The approval letter specified that if Governor DuPont or any other representatives had any objections to the conditions of delegation they were to respond within ten (10) days after receipt of the letter. As of this date, no objections have been received.

II. Regulations Affected by This Document

Pursuant to the delegation of authority for certain Standards of Performance for New Stationary Sources to the State of Delaware, EPA is today amending 40 CFR 60.4, *Address*, to reflect this delegation. A Notice announcing this delegation (was) published on February 15, 1978, in the Federal Register. The amended § 60.4, which adds the address of the Delaware Department of Natural Resources and Environmental Control, to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

III. General

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on September 30, 1977, and it serves no purpose to delay the technical change of this address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended, 42 U.S.C. 1857c-6.

Dated: January 31, 1978.

Jack J. Schramm,
Regional Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4, paragraph (b) is amended by revising subparagraph (I) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)-(H) * * *

(I) State of Delaware (for fossil fuel-fired steam generators; incinerators; nitric acid plants; asphalt concrete plants; storage vessels for petroleum liquids; and sewage treatment plants only): Delaware Department of Natural Resources and Environmental Control, Edward Tatnall Building, Dover, Del. 19901.

[FR Doc. 78-4268 Filed 2-15-78; 8:45 am]

Title 40—Protection of the Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 833-1]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Kraft Pulp Mills

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: The standards limit emissions of total reduced sulfur (TRS) and particulate matter from new, modified, and reconstructed kraft pulp mills. The standards implement the Clean Air Act and are based on the Administrator's determination that emissions from kraft pulp mills contribute significantly to air pollution. The intended effect of these standards is to require new, modified, and reconstructed kraft pulp mills to use the best demonstrated system of continuous emission reduction.

EFFECTIVE DATE: February 23, 1978.

ADDRESSES: The Standards Support and Environmental Impact Statement (SSEIS) may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, N.C. 27711 (specify "Standards Support and Environmental Impact Statement, Volume 2: Promulgated Standards of Performance for Kraft Pulp Mills" (EPA-450/2-76-014b)). Copies of all comment letters received from interested persons participating in this rulemaking are available for inspection and copying during normal business hours at EPA's Public Information Reference Unit, Room 2922 (EPA Library), 401 M Street SW., Washington, D.C.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone No. 919-541-5271.

SUPPLEMENTARY INFORMATION: On September 24, 1976 (41 FR 42012), standards of performance were proposed for new, modified, and reconstructed kraft pulp mills under section 111 of the Clean Air Act, as amended. The significant comments that were received during the public comment period have been carefully reviewed and considered and, where determined by the Administrator to be appropriate, changes have been included in this notice of final rulemaking.

THE STANDARDS

The standards limit emissions of particulate matter from three affected facilities at kraft pulp mills. The limits are: 0.10 gram per dry standard cubic meter (g/dscm) at 8 percent oxygen for recovery furnaces, 0.10 gram per kilogram of black liquor solids (dry weight) (g/kg BLS) for smelt dissolving tanks, 0.15 g/dscm at 10 percent oxygen for lime kilns when burning gas, and 0.30 g/dscm at 10 percent oxygen for lime kilns when burning oil. Visible emissions from recovery furnaces are limited to 35 percent opacity.

The standards also limit emissions of TRS from eight affected facilities at kraft pulp mills. The limits are: 5 parts per million (ppm) by volume at 10 percent oxygen from the digester systems, multiple-effect evaporator systems, brown stock washer systems, black liquor oxidation systems, and condensate stripper systems; 5 ppm by volume at 8 percent oxygen from straight kraft recovery furnaces, 8 ppm by volume at 10 percent oxygen from lime kilns; and 25 ppm by volume at 8 percent oxygen from cross recovery furnaces, which are defined as furnaces burning at least 7 percent neutral sulfite semi-chemical (NSSC) liquor and having a green liquor sulfidity of at least 28 percent. In addition, TRS emissions from smelt dissolving tanks are limited to 0.0084 g/kg BLS.

The proposed TRS standard for the lime kiln has been changed, a separate TRS standard for cross recovery furnaces has been developed, and the proposed format of the standards for smelt dissolving tanks, digesters, multiple-effect evaporators, brown stock washers, black liquor oxidation and condensate strippers have been changed. The TRS, particulate matter and opacity standards for the other facilities, however, are essentially the same as those proposed.

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect emission limits achievable with the best adequately demonstrated technological system of continuous emission reduction considering the cost of achieving such emission reductions and any nonair quality health, environmental, and energy impacts. State implementation plans (SIP's) approved or promulgated under section 110 of the Act, on the other hand, must provide for the attainment and maintenance of national ambient air quality standards (NAAQS) designed to protect public health and welfare. For that purpose SIP's must in some cases require greater emission reductions than those required by standards of performance for new sources. Section 173(2) of the Clean Air Act, as amended in 1977, requires, among other things, that a new or modified source constructed in an area which exceeds the NAAQS must reduce emissions to the level which reflects the "lowest achievable emission rate" for such category of source, unless the owner or operator demonstrates that the source cannot achieve such an emission rate. In no event can the emission rate exceed any applicable standard of performance.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area which falls under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology. The term "best available control technology" (BACT) means "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines it achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act."

Standards of performance should not be viewed as the ultimate in achievable emission control and should not preclude the imposition of a more stringent emission standard, where appropriate. For example, cost of achivement may be an important factor in determining standards of performance applicable to all areas of the country (clean as well as dirty). Costs must be accorded far less weight in determining the "lowest achievable emission rate" for new or modified sources locating in areas violating statutorily-mandated health and welfare standards. Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. This in no way should preclude its use in situations where cost is a lesser consideration, such as determination of the "lowest achievable emission rate."

In addition, States are free under section 116 of the Act to establish even more stringent emission limits than

those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

Environmental and Economic Impact

The promulgated standards will reduce particulate emissions about 50 percent below requirements of the average existing State regulations. TRS emissions will be reduced by about 80 percent below requirements of the average existing State regulations, and this reduction will prevent odor problems from arising at most new kraft pulp mills. The secondary environmental impacts of the promulgated standard will be slight increases in water demand and wastewater treatment requirements. The energy impact of the promulgated standards will be small, increasing national energy consumption in 1980 by the equivalent of only 1.4 million barrels per year of No. 6 oil. The economic impact will be small with fifth-year annualized costs being estimated at $33 million.

Public Participation

Prior to proposal of the standards, interested parties were advised by public notice in the Federal Register of a meeting of the National Air Pollution Control Techniques Advisory Committee. In addition, copies of the proposed standards and the Standards Support and Environmental Impact Statement (SSEIS) were distrubited to members of the kraft pulp industry and several environmental groups at the time of proposal. The public comment period extended from September 24, 1976, to March 14, 1977, and resulted in 42 comment letters with 28 of these letters coming from the industry, 12 from various regulatory agencies, and two from U.S. citizens. Several comments resulted in changes to the proposed standards. A detailed discussion of the comments and changes which resulted is presented in Volume 2 of the SSEIS. A summary is presented here.

Significant Comments and Changes Made in the Proposed Regulations

Most of the comment letters received contained multiple comments. The most significant comments and changes made to the proposed regulations are discussed below.

Impacts of the proposed standards

Several commenters expressed concern about the increased energy consumption which would result from compliance with proposed standards. These commenters felt that this would conflict with the Department of Energy's goal to reduce total energy consumption in the pulp and paper industry by 14 percent. This factor was considered in the analysis of the energy impact associated with the standards and is discussed in the SSEIS. Although the standards will increase the difficulty of attaining this energy reduction goal, the 4.3 percent increase in energy usage that will be required by new, modified, or reconstructed by kraft pulp mills to comply with the standards is considered reasonable in comparison to the benefits which will result from the corresponding reduction in TRS and particulate matter emissions.

Emission control technology

Most of the comments received regarding emission control technology concerned the application of this technology to either lime kilns or recovery furnaces. A few comments, however, expressed concern with the use of the oxygen correction factor included in the proposed standards for both lime kilns and recovery furnaces. These commenters pointed out that adjusting the concentration of particulate matter and TRS emissions to 10 percent oxygen for lime kilns and 8 percent oxygen for recovery furnaces only when the oxygen concentration exceeded these values effectively placed more stringent standards on the most energy-efficient operators. To ensure that the standard is equitable for all operators, these commenters suggested that the measured particulate matter and TRS concentrations should always be adjusted to 10 percent oxygen for the lime kiln and 8 percent oxygen for the recovery furnace.

These comments are valid. Requiring a lime kiln or recovery furnace with a low oxygen concentration to meet the same emission concentration as a lime kiln or recovery furnace with a high oxygen concentration would effectively place a more stringent emission limit on the kiln or furnace with the low oxygen concentration. Consequently, the promulgated standards require correction of particulate matter and TRS concentrations to 10 percent or 8 percent oxygen, as appropriate, in all cases.

Lime Kilns. Numerous comments were received on the emission control technology for lime kilns. The main points questioned by the commenters were: (a) Whether caustic scrubbing is effective in reducing TRS emissions from lime kilns; (b) whether an overdesign of the mud washing facilities at lime kiln E was responsible for the lower TRS emissions observed at this lime kiln; and (c) the adequacy of the data base used in developing the TRS standard.

The effectiveness of caustic scrubbing is substantiated by comparison of TRS emissions during brief periods when caustic was not being added to the scrubber at lime kiln E, with TRS emissions during normal operation at lime kiln E when caustic is being added to the scrubber. These observations clearly indicate that TRS emissions would be higher if caustic was not used in the scrubber. The ability of caustic scrubbing to reduce TRS emissions is also substantiated by the experience at another kraft pulp mill which was able to reduce TRS emissions from its lime kiln from 40-50 ppm to about 20 ppm merely by adding caustic to the scrubber. These factors, coupled with the emission data showing higher TRS emissions from those lime kilns which employed only efficient mud washing and good lime kiln process control, clearly show that caustic scrubbing reduces TRS emissions.

The mud washing facilities at lime kiln E are larger than those at other kraft pulp mills of equivalent pulp capacity. This "overdesign" resulted from initial plans of the company to process lime mud from waste water treatment. These waste water treatment plans were later abandoned. Since the quality or efficiency of mud washing has been shown to be a significant factor in reducing TRS emissions from lime kilns, the larger mud washing facilities at lime kiln E undoubtedly contributed to the low TRS emissions observed at this kiln. With the data available, however, it is not possible to separate the relative contribution of these mud washing facilities to the low TRS emissions observed from the relative contributions of good process operation of the lime kiln and caustic scrubbing.

Comments questioning the adequacy of the data base used in developing the standards for lime kilns were mainly directed toward the following points: the TRS standard was based on only one lime kiln; sampling losses which may have occurred during testing were not taken into account; and no lime kiln met both the TRS standard and the particulate standard.

As mentioned above, the TRS standard is based upon the emission control system installed at lime kiln E (i.e., efficient mud washing, good lime kiln process operation, and caustic scrubbing). While it is true that no other lime kiln in the United States is currently achieving the TRS emission levels observed at lime kiln E, there is no other lime kiln in the United States which is using the same emission control system that is employed at this facility. As discussed in the SSEIS, an analysis of the various parameters influencing TRS emissions from lime kilns indicates that this system of emission reduction could be applied to

all new, modified, or reconstructed lime kilns and achieve the same reduction in emissions as observed at lime kiln E. Section 111 of the Clean Air Act requires that "standards of performance reflect the degree of emission reduction achievable through the application of the best system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated for that category of sources." Litigation of standards of performance has resulted in clarification of the term "adequately demonstrated." In Portland Cement Association v. Ruckelshaus (486 F. 2d 375, D.C. Circuit, 1973), the standards of performance were viewed by the Court as "technology-forcing." Thus, while a system of emission reduction must be available for use to be considered adequately demonstrated, it does not have to be in routine use. However, in order to ensure that the numerical emission limit selected was consistent with proper operation and maintenance of the emission control system on lime kiln E, continuous monitoring data was examined. This analysis indicated that an emission source test of lime kiln E would have found TRS emission above 5 ppm greater than 5 percent of the time. This analysis also indicated, however, that it was very unlikely that an emission source test of lime kiln E would have found TRS emissions above 8 ppm. Thus, it appeared that the 5 ppm TRS numerical emission limit included in the proposed standard for lime kilns was too stringent. Accordingly, the numerical emission limit included in the promulgated TRS standard for lime kilns has been revised to 8 ppm. As discussed later in this preamble, consistent with this change in the numerical emission limit, the excess emissions allowance included within the emission monitoring requirements has been eliminated.

This does not reflect a change in the basis for the standard. The standard is still based on the best system of emission reduction, considering costs, for controlling TRS emissions from lime kilns (i.e., efficient mud washing, good lime kiln process operation, and caustic scrubbing). This system, or one equivalent to it, will still be required to comply with the standard.

Since proposal of the standards, sample losses of up to 20 percent during emission source testing have been confirmed. Although these losses were not considered in selecting the numerical emission limit included in the proposed TRS emission standard, they have been considered in selecting the numerical emission limit included in the promulgated standard. Also, since the amount of sample loss that occurs within the TRS emission measurement system during source testing can be determined, procedures have been added to Reference Method 16 requiring determination of these losses during each source test and adjustment of the emission data obtained to take these losses into account.

With regard to the ability of a lime kiln to comply with both the TRS emission standard and the particulate emission standard simultaneously, caustic scrubbing will tend to increase particulate emissions due to release of sodium fume from the scrubbing liquor. Compared to the concentration of particulate matter permitted in the gases discharged to the atmosphere, however, the potential contribution of sodium fume from caustic scrubbing is quite small. Consequently, with proper operation and maintenance, sodium fume due to caustic scrubbing will not cause particulate emissions from a lime kiln to exceed the numerical emission limit included in the promulgated standard.

Recovery Furnace. A number of comments were received regarding both the proposed TRS emission standard and the proposed particulate emission standard for recovery furnaces. Basically, the major issue was whether a cross recovery furnace could comply with the 5 ppm TRS standard or whether a separate standard was necessary.

Review of the data and information submitted with these comments indicates that the operation of cross recovery furnaces is substantially different from that of straight kraft recovery furnaces. The sulfidity of the black liquor burned in cross recovery furnaces and the heat content of the liquor, both of which are significant factors influencing TRS emissions, are considerably different from the levels found in straight kraft recovery furnaces.

Analysis of the data indicated that TRS emissions were generally less than 25 ppm, with only occasional excursions exceeding this level. Consequently, the promulgated TRS emission standard has been revised to include a separate TRS numerical emission limit of 25 ppm for cross recovery furnaces.

Smelt Dissolving Tank. Numerous comments were received concerning the format of the proposed TRS and particulate emission standards for smelt dissolving tanks. These comments pointed out that standards in terms of emissions per unit of air-dried pulp were inequitable for kraft pulp mills which produced low-yield pulps since both TRS and particulate emissions from the smelt dissolving tanks are proportional to the tons of black liquor solids fed into the tanks. The black liquor solids produced per ton of air-dried pulp, however, can vary substantially from mill to mill. A standard in terms of emissions per unit of air-dried pulp, therefore, requires greater control of emissions at kraft pulp mills which use low-yield pulps (higher solids-to-pulp ratio).

Review of these comments does indeed indicate that the format of the proposed standards was inequitable. The format of the promulgated standards, therefore, has been revised to emissions per unit of black liquor solids fed to the smelt dissolving tanks. Since the percent solids and black liquor flow rate to the recovery furnace is routinely monitored at kraft pulp mills, the weight of black liquor solids corresponding to a particular emissions period will be easy to determine.

Brown Stock Washers. Several comments expressed concern about combustion of the high volume-low TRS concentration gases discharged from brown stock washers and black liquor oxidation facilities in recovery furnaces without facing a serious risk of explosions. As discussed in the SSEIS, information obtained from two kraft pulp mill operators indicates that this practice is both safe and reliable when it is accompanied by careful engineering and operating practices. Danger of an explosion occurring is essentially eliminated by introducing the gases high in the furnace. Since some older furnaces do not have the capability to accept large volumes of gases at higher combustion ports, this practice may not be safe for some existing furnaces. In addition, the costs associated with altering these furnaces to accept these gases are frequently prohibitive. Consequently, the promulgated standards include an exemption for new, modified, or reconstructed brown stock washers and black liquor oxidation facilities within existing kraft pulp mills where combustion of these gases in an existing facility is not feasible from a safety or economic standpoint.

CONTINUOUS MONITORING

Numerous comments were received concerning the proposed continuous monitoring requirements. Generally, these comments questioned the requirement to install TRS monitors in light of the absence of performance specifications for these monitors.

At the time of proposal of the standards, both EPA and the kraft pulp mill industry were engaged in developing performance specifications for TRS continuous emission monitoring systems. It was expected that this work would lead to performance specifications for these monitoring systems by the time the standards of performance were promulgated. Unfortunately, this is not the case. In a joint EPA/industry effort, the compatibility of various TRS emission monitoring

methods with Reference Method 16, which is the performance test method to determine TRS emissions, is still under study. There is little doubt but that these TRS emission monitoring systems will be shown to be compatible with Reference Method 16, and that performance specifications for these systems will be developed. Consequently, the promulgated standards include TRS continuous emission monitoring requirements. These requirements, however, will not become effective until performance specifications for TRS continuous emission monitoring systems have been developed. To accommodate this situation, not only for the promulgated standards for kraft pulp mills, but also for standards of performance that may be developed in the future that may also face this situation, section 60.13 of the General Provisions for subpart 60 is amended to provide that continuous monitoring systems need not be installed until performance specifications for these systems are promulgated under Appendix B to subpart 60. This will ensure that all facilities which are covered by standards of performance will eventually install continuous emission monitoring systems where required.

EXCESS EMISSIONS

Numerous comments were received which were concerned with the excess emission allowances and the reporting requirements for excess emissions. In general, these comments reflected a lack of understanding with regard to the concept of excess emissions. Consequently, a brief review of this concept is appropriate.

Standards of performance have two major objectives. The first is installation of the best system of emission reduction, considering costs; and the second is continued proper operation and maintenance of the system throughout its useful life. Since the numerical emission limit included in standards of performance is selected to reflect the performance of the best system of emission reduction under conditions of proper operation and maintenance, the performance test, under 40 CFR 60.8 represents the ability of the source to meet these objectives. Performance tests, however, are often time consuming and complex. As a result, while the performance test is an excellent mechanism for achieving these objectives, it is rather cumbersome and inconvenient for routinely achieving these objectives. Therefore, the Agency believes that continuous monitors must play an important role in meeting these objectives.

Excess emissions are defined as emissions exceeding the numerical emission limit included in a standard of performance. Continuous emission monitoring, therefore, identifies periods of excess emissions and when combined with the requirement that these periods be reported to EPA, it provides the Agency with a useful mechanism for achieving the previously mentioned objectives.

Continuous emission monitoring, however, will identify all periods of excess emissions, including those which are not the result of improper operation and maintenance. Excess emissions due to start-ups, shutdowns, and malfunctions, for example, are unavoidable or beyond the control of an owner or operator and cannot be attributed to improper operation and maintenance. Similarly, excess emissions as a result of some inherent variability or fluctation within a process which influences emissions cannot be attributed to improper operation and maintenance, unless these fluctations could be controlled by more carefully attending to those process operating parameters during routine operation which have little effect on operation of the process, but which may have a significant effect on emissions.

To quantify the potential for excess emissions due to inherent variability in a process, continuous monitoring data are used whenever possible to calculate an excess emission allowance. For TRS emissions at kraft pulp mills, this allowance is defined as follows. If a calendar quarter is divided into discrete contiguous 12-hour time periods, the excess emission allowance is expressed as the percentage of these time periods. Excess emissions may occur as the result of unavoidable variability within the kraft pulping process. Thus, the excess emissions allowance represents the potential for excess emissions under conditions of proper operation and maintenance in the absence of start-ups, shutdowns and malfunctions, and is used as a guideline or screening mechanism for interpreting the data generated by the excess emission reporting requirements.

Although the excess emission reporting requirements provide a mechanism for achieving the objective of proper operation and maintenance of the best system of emission reduction, this mechanism is not necessarily a direct indicator of improper operation and maintenance. Consequently, excess emission reports must be reviewed and interpreted for proper decisionmaking.

In general, the comments received concerning the excess emission reporting requirements questioned: (1) The adequacy of the TRS excess emission allowance for lime kilns and (2) the lack of a TRS excess emission allowance for recovery furnaces.

With regard to the adequacy of the TRS excess emissions allowance for lime kilns, a reevaluation of the TRS emission data from lime kiln E led the Agency to the conclusion that, for a TRS emission limit of 5 ppm, an excess emission allowance of 6 percent was appropriate. However, a similar analysis also indicates that an excess emission allowance is not appropriate at a TRS emission level of 8 ppm. Accordingly, the excess emission reporting requirements included in the promulgated standard for lime kilns contains no excess emission allowance. This does not represent a change in the basis of the standard. The standard will still require installation of the best system of emission reduction, considering costs (i.e., efficient mud washing, good lime kiln process operation, and caustic scrubbing; or an alternative system equivalent to the performance of this system).

With regard to the lack of a TRS excess emission allowance for recovery furnaces, at the time of proposal of the standards, no TRS continuous emission monitoring data were available from a well-controlled and well operated recovery furnace which could be used to determine an excess emission allowance. Several months of TRS continuous emission monitoring data, however, were submitted with the comments received from the operator of recovery furnace D concerning this point.

A review of the data indicates that, while some of the excursions of TRS emissions above 5 ppm reflected either improper operation and maintenance, or start-ups, shutdowns, or malfunctions, most of these excursions reflected unavoidable normal variability in the operation of a kraft pulp mill recovery furnace. Discounting those excursions in emissions from the data which were due to improper operation and maintenance, or start-ups, shutdowns, or malfunctions indicates that an excess emission allowance of 1 percent is appropriate for all recovery furnaces.

Including an excess emissions allowance in the promulgated standards for recovery furnaces, but not for lime kilns, is a reversal of the proposed requirements. Including such an allowance for recovery furnaces but not for lime kilns, however, is consistent with the nature of the different emission control systems which were selected as the bases for these standards. The emission control system upon which the TRS standard for recovery furnaces is based consists of black liquor oxidation and good process operation of the recovery furnace for direct recovery furnaces, and good process operation alone for indirect recovery furnaces. Neither of these emission control systems are particularly well suited to controlling fluctuations in the kraft pulping process. Thus, fluctuations in the process tend to pass through the emission control system and show up as fluctuations in TRS emissions.

The emission control system upon which the TRS standard for lime kilns

is based consists of efficient mud washing, good process operation of the lime kiln, and caustic scrubbing of the gases discharged from the lime kiln. As with the emission control system upon which the standard for recovery furnaces is based, the first two emission control techniques (i.e., mud washing and good process operation) are not particularly well suited to controlling fluctuations in the kraft pulping process. The third emission control technique, however, caustic scrubbing, is an "add-on" emission control technique that can be designed to accommodate fluctuations in TRS emissions and minimize or essentially eliminate these fluctuations.

EMISSION TESTING

A few comments were received which questioned the validity of the results obtained by Reference Method 16, due to sample losses and sulfur dioxide (SO_2) interference.

With regard to the validity of the results obtained by Reference Method 16, as mentioned earlier, during the emission testing program, it was not widely known that sample losses could occur within the TRS emission measurement system. Since proposal of the standards, however, sample losses of up to 20 percent during emission source testing have been confirmed. Although these losses were not considered in selecting the numerical emission limits included in the proposed TRS emission standards, they have been considered in selecting the numerical emission limit included in the promulgated standards. Also, since the amount of sample loss that occurs within the TRS emission measurement system during source testing can be determined, procedures have been added to Reference Method 16 requiring determination of these losses during each source test and adjustment of the emission data obtained to take these losses into account. This will ensure that the TRS emission data obtained during a performance test are accurate.

It has also been confirmed that high concentrations of SO_2 will interfere with the determination of TRS emissions to some extent. At this point, however, it is not known what SO_2 concentration levels will result in a significant loss of accuracy in determining TRS emissions. The ability of a citrate scrubber to selectively remove SO_2 prior to measurement of TRS emissions is now being tested. In addition, various chromatographic columns might exist which would effectively resolve this problem. As soon as an appropriate technique is developed to overcome this problem, Reference Method 16 will be amended.

This problem of SO_2 interference will not present major difficulties to the use of Reference Method 16. Relatively high SO_2 concentration levels were observed in only one EPA emission source test. Accordingly, high SO_2 concentration levels are probably not a frequent occurrence within kraft pulp mills. More importantly, however, high SO_2 concentrations only interfere with the determination of methyl mercaptan in the emission measurement system outlined in Reference Method 16. Since methyl mercaptan is usually only a small contributor to total TRS emissions, neglecting methyl mercaptan where this interference occurs should not seriously affect the determination of TRS emissions. Consequently, Reference Method 16 can be used to enforce the promulgated standards without major difficulties.

Miscellaneous: The effective date of this regulation is February 24, 1976. Section 111(b)(1)(B) of the Clean Air Act provides that standards of performance or revisions of them become effective upon promulgation and apply to affected facilities, construction or modification of which was commenced after the date of proposal (September 24, 1976).

NOTE.—An economic assessment has been prepared as required under section 317 of the Act. This also satisfies the requirements of Executive Orders 11821 and OMB Circular A-107.

Dated: February 10, 1978.

BARBARA BLUM,
Acting Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

Subpart A—General Provisions

1. Section 60.13 is amended to clarify the provisions in paragraph (a) by revising paragraph (a) to read as follows:

§ 60.13 Monitoring requirements.

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring system under Appendix B to this part, unless:

(1) The continuous monitoring system is subject to the provisions of paragraphs (c)(2) and (c)(3) of this section, or

(2) otherwise specified in an applicable subpart or by the Administrator.

* * * * *

2. Part 60 is amended by adding subpart BB as follows:

Subpart BB—Standards of Performance for Kraft Pulp Mills

Sec.

60.280 Applicability and designation of affected facility.
60.281 Definitions.
60.282 Standard for particulate matter.
60.283 Standard for total reduced sulfur (TRS).
60.284 Monitoring of emissions and operations.
60.285 Test methods and procedures.

AUTHORITY: Secs. 111, 301(a) of the Clean Air Act, as amended [42 U.S.C. 7411, 7601(a)], and additional authority as noted below.

Subpart BB—Standards of Performance for Kraft Pulp Mills

60.280 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in kraft pulp mills: digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, recovery furnace, smelt dissolving tank, lime kiln, and condensate stripper system. In pulp mills where kraft pulping is combined with neutral sulfite semichemical pulping, the provisions of this subpart are applicable when any portion of the material charged to an affected facility is produced by the kraft pulping operation.

(b) Any facility under paragraph (a) of this section that commences construction or modification after September 24, 1976, is subject to the requirements of this subpart.

§ 60.281 Definitions.

As used in this subpart, all terms not defined herein shall have the same meaning given them in the Act and in Subpart A.

(a) "Kraft pulp mill" means any stationary source which produces pulp from wood by cooking (digesting) wood chips in a water solution of sodium hydroxide and sodium sulfide (white liquor) at high temperature and pressure. Regeneration of the cooking chemicals through a recovery process is also considered part of the kraft pulp mill.

(b) "Neutral sulfite semichemical pulping operation" means any operation in which pulp is produced from wood by cooking (digesting) wood chips in a solution of sodium sulfite and sodium bicarbonate, followed by mechanical defibrating (grinding).

(c) "Total reduced sulfur (TRS)" means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide, that are released during the kraft pulping operation and measured by Reference Method 16.

(d) "Digester system" means each continuous digester or each batch digester used for the cooking of wood in white liquor, and associated flash tank(s), below tank(s), chip steamer(s), and condenser(s).

(e) "Brown stock washer system" means brown stock washers and associated knotters, vacuum pumps, and fil-

trate tanks used to wash the pulp following the digester system.

(f) "Multiple-effect evaporator system" means the multiple-effect evaporators and associated condenser(s) and hotwell(s) used to concentrate the spent cooking liquid that is separated from the pulp (black liquor).

(g) "Black liquor oxidation system" means the vessels used to oxidize, with air or oxygen, the black liquor, and associated storage tank(s).

(h) "Recovery furnace" means either a straight kraft recovery furnace or a cross recovery furnace, and includes the direct-contact evaporator for a direct-contact furnace.

(i) "Straight kraft recovery furnace" means a furnace used to recover chemicals consisting primarily of sodium and sulfur compounds by burning black liquor which on a quarterly basis contains 7 weight percent or less of the total pulp solids from the neutral sulfite semichemical process or has green liquor sulfidity of 28 percent or less.

(j) "Cross recovery furnace" means a furnace used to recover chemicals consisting primarily of sodium and sulfur compounds by burning black liquor which on a quarterly basis contains more than 7 weight percent of the total pulp solids from the neutral sulfite semichemical process and has a green liquor sulfidity of more than 28 percent.

(k) "Black liquor solids" means the dry weight of the solids which enter the recovery furnace in the black liquor.

(l) "Green liquor sulfidity" means the sulfidity of the liquor which leaves the smelt dissolving tank.

(m) "Smelt dissolving tank" means a vessel used for dissolving the smelt collected from the recovery furnace.

(n) "Lime kiln" means a unit used to calcine lime mud, which consists primarily of calcium carbonate, into quicklime, which is calcium oxide.

(o) "Condensate stripper system" means a column, and associated condensers, used to strip, with air or steam, TRS compounds from condensate streams from various processes within a kraft pulp mill.

§ 60.282 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any recovery furnace any gases which:

(i) Contain particulate matter in excess of 0.10 g/dscm (0.044 gr/dscf) corrected to 8 percent oxygen.

(ii) Exhibit 35 percent opacity or greater.

(2) From any smelt dissolving tank any gases which contain particulate matter in excess of 0.1 g/kg black liquor solids (dry weight)[0.2 lb/ton black liquor solids (dry weight)].

(3) From any lime kiln any gases which contain particulate matter in excess of:

(i) 0.15 g/dscm (0.067 gr/dscf) corrected to 10 percent oxygen, when gaseous fossil fuel is burned.

(ii) 0.30 g/dscm (0.13 gr/dscf) corrected to 10 percent oxygen, when liquid fossil fuel is burned.

§ 60.283 Standard for total reduced sulfur (TRS).

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system any gases which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to 10 percent oxygen, unless the following conditions are met:

(i) The gases are combusted in a lime kiln subject to the provisions of paragraph (a)(5) of this section; or

(ii) The gases are combusted in a recovery furnace subject to the provisions of paragraphs (a)(2) or (a)(3) of this section; or

(iii) The gases are combusted with other waste gases in an incinerator or other device, or combusted in a lime kiln or recovery furnace not subject to the provisions of this subpart, and are subjected to a minimum temperature of 1200° F. for at least 0.5 second; or

(iv) It has been demonstrated to the Administrator's satisfaction by the owner or operator that incinerating the exhaust gases from a new, modified, or reconstructed black liquor oxidation system or brown stock washer system in an existing facility is technologically or economically not feasible. Any exempt system will become subject to the provisions of this subpart if the facility is changed so that the gases can be incinerated.

(2) From any straight kraft recovery furnace any gases which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to 8 percent oxygen.

(3) From any cross recovery furnace any gases which contain TRS in excess of 25 ppm by volume on a dry basis, corrected to 8 percent oxygen.

(4) From any smelt dissolving tank any gases which contain TRS in excess of 0.0084 g/kg black liquor solids (dry weight) [0.0168 lb/ton liquor solids (dry weight)].

(5) From any lime kiln any gases which contain TRS in excess of 8 ppm by volume on a dry basis, corrected to 10 percent oxygen.

§ 60.284 Monitoring of emissions and operations.

(a) Any owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate the following continuous monitoring systems:

(1) A continuous monitoring system to monitor and record the opacity of the gases discharged into the atmosphere from any recovery furnace. The span of this system shall be set at 70 percent opacity.

(2) Continuous monitoring systems to monitor and record the concentration of TRS emissions on a dry basis and the percent of oxygen by volume on a dry basis in the gases discharged into the atmosphere from any lime kiln, recovery furnace, digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system, except where the provisions of § 60.283(a)(1) (iii) or (iv) apply. These systems shall be located downstream of the control device(s) and the span(s) of these continuous monitoring system(s) shall be set:

(i) At a TRS concentration of 30 ppm for the TRS continuous monitoring system, except that for any cross recovery furnace the span shall be set at 50 ppm.

(ii) At 20 percent oxygen for the continuous oxygen monitoring system.

(b) Any owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate the following continuous monitoring devices:

(1) A monitoring device which measures the combustion temperature at the point of incineration of effluent gases which are emitted from any digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system where the provisions of § 60.283(a)(1)(iii) apply. The monitoring device is to be certified by the manufacturer to be accurate within ±1 percent of the temperature being measured.

(2) For any lime kiln or smelt dissolving tank using a scrubber emission control device:

(i) A monitoring device for the continuous measurement of the pressure loss of the gas stream through the control equipment. The monitoring device is to be certified by the manufacturer to be accurate to within a gage pressure of ±500 pascals (ca. ±2 inches water gage pressure).

(ii) A monitoring device for the continuous measurement of the scrubbing liquid supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±15 percent of design scrubbing liquid supply pressure. The pressure sensor or tap is to

be located close to the scrubber liquid discharge point. The Administrator may be consulted for approval of alternative locations.

(c) Any owner or operator subject to the provisions of this subpart shall, except where the provisions of § 60.283(a)(1)(iv) or § 60.283(a)(4) apply.

(1) Calculate and record on a daily basis 12-hour average TRS concentrations for the two consecutive periods of each operating day. Each 12-hour average shall be determined as the arithmetic mean of the appropriate 12 contiguous 1-hour average total reduced sulfur concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section.

(2) Calculate and record on a daily basis 12-hour average oxygen concentrations for the two consecutive periods of each operating day for the recovery furnace and lime kiln. These 12-hour averages shall correspond to the 12-hour average TRS concentrations under paragraph (c)(1) of this section and shall be determined as an arithmetic mean of the appropriate 12 contiguous 1-hour average oxygen concentrations provided by each continuous monitoring system installed under paragraph (a)(2) of this section.

(3) Correct all 12-hour average TRS concentrations to 10 volume percent oxygen, except that all 12-hour average TRS concentration from a recovery furnace shall be corrected to 8 volume percent using the following equation:

$$C_{corr} = C_{meas} \times (21 - X/21 - Y)$$

where:

C_{corr} = the concentration corrected for oxygen.

C_{meas} = the concentration uncorrected for oxygen.

X = the volumetric oxygen concentration in percentage to be corrected to (8 percent for recovery furnaces and 10 percent for lime kilns, incinerators, or other devices).

Y = the measured 12-hour average volumetric oxygen concentration.

(d) For the purpose of reports required under § 60.7(c), any owner or operator subject to the provisions of this subpart shall report periods of excess emissions as follows:

(1) For emissions from any recovery furnace periods of excess emissions are:

(i) All 12-hour averages of TRS concentrations above 5 ppm by volume for straight kraft recovery furnaces and above 25 ppm by volume for cross recovery furnaces.

(ii) All 6-minute average opacities that exceed 35 percent.

(2) For emissions from any lime kiln, periods of excess emissions are all 12-hour average TRS concentration above 8 ppm by volume.

(3) For emissions from any digester system, brown stock washer system, multiple-effect evaporator system, black liquor oxidation system, or condensate stripper system periods of excess emissions are:

(i) All 12-hour average TRS concentrations above 5 ppm by volume unless the provisions of § 60.283(a)(1) (i), (ii), or (iv) apply; or

(ii) All periods in excess of 5 minutes and their duration during which the combustion temperature at the point of incineration is less than 1200° F. where the provisions of § 60.283(a)(1)(ii) apply.

(e) The Administrator will not consider periods of excess emissions reported under paragraph (d) of this section to be indicative of a violation of § 60.11(d) provided that:

(1) The percent of the total number of possible contiguous periods of excess emissions in a quarter (excluding periods of startup, shutdown, or malfunction and periods when the facility is not operating) during which excess emissions occur does not exceed:

(i) One percent for TRS emissions from recovery furnaces.

(ii) Six percent for average opacities from recovery furnaces.

(2) The Administrator determines that the affected facility, including air pollution control equipment, is maintained and operated in a manner which is consistent with good air pollution control practice for minimizing emissions during periods of excess emissions.

§ 60.285 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided under § 60.8(b), shall be used to determine compliance with § 60.282(a) as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) When determining compliance with § 60.282(a)(2), Method 2 for velocity and volumetric flow rate,

(4) Method 3 for gas analysis, and

(5) Method 9 for visible emissions.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.85 dscm/hr (0.53 dscf/min) except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator. Water shall be used as the cleanup solvent instead of acetone in the sample recovery procedure outlined in Method 5.

(c) Method 17 (in-stack filtration) may be used as an alternate method for Method 5 for determining compliance with § 60.282(a)(1)(i): *Provided*, That a constant value of 0.009 g/dscm (0.004 gr/dscf) is added to the results of Method 17 and the stack temperature is no greater than 205° C (ca. 400° F). Water shall be used as the cleanup solvent instead of acetone in the sample recovery procedure outlined in Method 17.

(d) For the purpose of determining compliance with § 60.283(a) (1), (2), (3), (4), and (5), the following reference methods shall be used:

(1) Method 16 for the concentration of TRS,

(2) Method 3 for gas analysis, and

(3) When determining compliance with § 60.283(a)(4), use the results of Method 2, Method 16, and the black liquor solids feed rate in the following equation to determine the TRS emission rate.

$$E = (C_{H_2S}F_{H_2S} + C_{MeSH}F_{MeSH} + C_{DMS}F_{DMS} + C_{DMDS}F_{DMDS})(Q_{sd})/BLS$$

Where:

E = mass of TRS emitted per unity of black liquor solids (g/kg) (lb/ton)

C_{H_2S} = average concentration of hydrogen sulfide (H_2S) during the test period, PPM.

C_{MeSH} = average concentration of methyl mercaptan (MeSH) during the test period, PPM.

C_{DMS} = average concentration of dimethyl sulfide (DMS) during the test period, PPM.

C_{DMDS} = average concentration of dimethyl disulfide (DMDS) during the test period, PPM.

F_{H_2S} = 0.001417 g/m³ PPM for metric units
= 0.08844 lb/ft³ PPM for English units

F_{MeSH} = 0.00200 g/m³ PPM for metric units
= 0.1248 lb/ft³ PPM for English units

F_{DMS} = 0.002583 g/m³ PPM for metric units
= 0.1612 lb/ft³ PPM for English units

F_{DMDS} = 0.003917 g/m³ PPM for metric units
= 0.2445 lb/ft³ PPM for English units

Q_{sd} = dry volumetric stack gas flow rate corrected to standard conditions, dscm/hr (dscf/hr)

BLS = black liquor solids feed rate, kg/hr (lb/hr)

(4) When determining whether a furnace is straight kraft recovery furnace or a cross recovery furnace, TAPPI Method T.624 shall be used to determine sodium sulfide, sodium hydroxide and sodium carbonate. These determinations shall be made three times daily from the green liquor and the daily average values shall be converted to sodium oxide (Na_2O) and substituted into the following equation to determine the green liquor sulfidity:

$$GLS = 100\ C_{Na_2S}/C_{Na_2S} + C_{NaOH} + C_{Na_2CO_3}$$

Where:

GLS = percent green liquor sulfidity

C_{Na_2S} = average concentration of Na_2S expressed as Na_2O (mg/l)

C_{NaOH} = average concentration of $NaOH$ expressed as Na_2O (mg/l)

$C_{Na_2CO_3}$ = average concentration of Na_2CO_3 expressed as Na_2O (mg/l)

(e) All concentrations of particulate matter and TRS required to be measured by this section from lime kilns or incinerators shall be corrected 10 volume percent oxygen and those concentrations from recovery furnaces

shall be corrected to 8 volume percent oxygen. These corrections shall be made in the manner specified in § 60.284(c)(3).

APPENDIX A—REFERENCE METHODS

(3) Method 16 and Method 17 are added to Appendix A as follows:

* * * * *

METHOD 16. SEMICONTINUOUS DETERMINATION OF SULFUR EMISSIONS FROM STATIONARY SOURCES

Introduction

The method described below uses the principle of gas chromatographic separation and flame photometric detection. Since there are many systems or sets of operating conditions that represent usable methods of determining sulfur emissions, all systems which employ this principle, but differ only in details of equipment and operation, may be used as alternative methods, provided that the criteria set below are met.

1. *Principle and Applicability.*

1.1 Principle. A gas sample is extracted from the emission source and diluted with clean dry air. An aliquot of the diluted sample is then analyzed for hydrogen sulfide (H_2S), methyl mercaptan (MeSH), dimethyl sulfide (DMS) and dimethyl disulfide (DMDS) by gas chromatographic (GC) separation and flame photometric detection (FPD). These four compounds are known collectively as total reduced sulfur (TRS).

1.2 Applicability. This method is applicable for determination of TRS compounds from recovery furnaces, lime kilns, and smelt dissolving tanks at kraft pulp mills.

2. *Range and Sensitivity.*

2.1 Range. Coupled with a gas chromatographic system utilizing a ten milliliter sample size, the maximum limit of the FPD for each sulfur compound is approximately 1 ppm. This limit is expanded by dilution of the sample gas before analysis. Kraft mill gas samples are normally diluted tenfold (9:1), resulting in an upper limit of about 10 ppm for each compound.

For sources with emission levels between 10 and 100 ppm, the measuring range can be best extended by reducing the sample size to 1 milliliter.

2.2 Using the sample size, the minimum detectable concentration is approximately 50 ppb.

3. *Interferences.*

3.1 Moisture Condensation. Moisture condensation in the sample delivery system, the analytical column, or the FPD burner block can cause losses or interferences. This potential is eliminated by heating the sample line, and by conditioning the sample with dry dilution air to lower its dew point below the operating temperature of the GC/FPD analytical system prior to analysis.

3.2 Carbon Monoxide and Carbon Dioxide. CO and CO_2 have substantial desensitizing effect on the flame photometric detector even after 9:1 dilution. Acceptable systems must demonstrate that they have eliminated this interference by some procedure such as eluting these compounds before any of the compounds to be measured. Compliance with this requirement can be demonstrated by submitting chromatograms of calibration gases with and without CO_2 in the diluent gas. The CO_2 level should be approximately 10 percent for the case with CO_2 present. The two chromatographs should show agreement within the precision limits of Section 4.1.

3.3 Particulate Matter. Particulate matter in gas samples can cause interference by eventual clogging of the analytical system. This interference must be eliminated by use of a probe filter.

3.4 Sulfur Dioxide. SO_2 is not a specific interferent but may be present in such large amounts that it cannot be effectively separated from other compounds of interest. The procedure must be designed to eliminate this problem either by the choice of separation columns or by removal of SO_2 from the sample.

Compliance with this section can be demonstrated by submitting chromatographs of calibration gases with SO_2 present in the same quantities expected from the emission source to be tested. Acceptable systems shall show baseline separation with the amplifier attenuation set so that the reduced sulfur compound of concern is at least 50 percent of full scale. Base line separation is defined as a return to zero ± percent in the interval between peaks.

4. *Precision and Accuracy.*

4.1 GC/FPD and Dilution System Calibration Precision. A series of three consecutive injections of the same calibration gas, at any dilution, shall produce results which do not vary by more than ±3 percent from the mean of the three injections.

4.2 GC/FPD and Dilution System Calibration Drift. The calibration drift determined from the mean of three injections made at the beginning and end of any 8-hour period shall not exceed ± percent.

4.3 System Calibration Accuracy. The complete system must quantitatively transport and analyze with an accuracy of 20 percent. A correction factor is developed to adjust calibration accuracy to 100 percent.

5. *Apparatus* (See Figure 16-1).

5.1.1 Probe. The probe must be made of inert material such as stainless steel or glass. It should be designed to incorporate a filter and to allow calibration gas to enter the probe at or near the sample entry point. Any portion of the probe not exposed to the stack gas must be heated to prevent moisture condensation.

5.1.2 Sample Line. The sample line must be made of Teflon,[1] no greater than 1.3 cm (½) inside diameter. All parts from the probe to the dilution system must be thermostatically heated to 120° C.

5.1.3 Sample Pump. The sample pump shall be a leakless Teflon-coated diaphragm type or equivalent. If the pump is upstream of the dilution system, the pump head must be heated to 120° C.

5.2 Dilution System. The dilution system must be constructed such that all sample contacts are made of inert materials (e.g., stainless steel or Teflon). It must be heated to 120° C. and be capable of approximately a 9:1 dilution of the sample.

5.3 Gas Chromatograph. The gas chromatograph must have at least the following components:

5.3.1 Oven. Capable of maintaining the separation column at the proper operating temperature ±1° C.

5.3.2 Temperature Gauge. To monitor column oven, detector, and exhaust temperature ±1° C.

5.3.3 Flow System. Gas metering system to measure sample, fuel, combustion gas, and carrier gas flows.

[1] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

5.3.4 Flame Photometric Detector.

5.3.4.1 Electrometer. Capable of full scale amplification of linear ranges of 10^{-9} to 10^{-4} amperes full scale.

5.3.4.2 Power Supply. Capable of delivering up to 750 volts.

5.3.4.3 Recorder. Compatible with the output voltage range of the electrometer.

5.4 Gas Chromatograph Columns. The column system must be demonstrated to be capble of resolving the four major reduced sulfur compounds: H_2S, MeSH, DMS, and DMDS. It must also demonstrate freedom from known interferences.

To demonstrate that adequate resolution has been achieved, the tester must submit a chromatograph of a calibration gas containing all four of the TRS compounds in the concentration range of the applicable standard. Adequate resolution will be defined as base line separation of adjacent peaks when the amplifier attenuation is set so that the smaller peak is at least 50 percent of full scale. Base line separation is defined in Section 3.4. Systems not meeting this criteria may be considered alternate methods subject to the approval of the Administrator.

5.5. Calibration System. The calibration system must contain the following components.

5.5.1 Tube Chamber. Chamber of glass or Teflon of sufficient dimensions to house permeation tubes.

5.5.2 Flow System. To measure air flow over permeation tubes at ±2 percent. Each flowmeter shall be calibrated after a complete test series with a wet test meter. If the flow measuring device differs from the wet test meter by 5 percent, the completed test shall be discarded. Alternatively, the tester may elect to use the flow data that would yield the lowest flow measurement. Calibration with a wet test meter before a test is optional.

5.5.3 Constant Temperature Bath. Device capable of maintaining the permeation tubes at the calibration temperature within ±0.1° C.

5.5.4 Temperature Gauge. Thermometer or equivalent to monitor bath temperature within ±1° C.

6. *Reagents.*

6.1 Fuel. Hydrogen (H_2) prepurified grade or better.

6.2 Combustion Gas. Oxygen (O_2) or air, research purity or better.

6.3 Carrier Gas. Prepurified grade or better.

6.4 Diluent. Air containing less than 50 ppb total sulfur compounds and less than 10 ppm each of moisture and total hydrocarbons. This gas must be heated prior to mixing with the sample to avoid water condensation at the point of contact.

6.5 Calibration Gases. Permeation tubes, one each of H_2S, MeSH, DMS, and DMDS, agravimetrically calibrated and certified at some convenient operating temperature. These tubes consist of hermetically sealed FEP Teflon tubing in which a liquified gaseous substance is enclosed. The enclosed gas permeates through the tubing wall at a constant rate. When the temperature is constant, calibration gases covering a wide range of known concentrations can be generated by varying and accurately measuring the flow rate of diluent gas passing over the tubes. These calibration gases are used to calibrate the GC/FPD system and the dilution system.

7. *Pretest Procedures.* The following procedures are optional but would be helpful in preventing any problem which might occur later and invalidate the entire test.

7.1 After the complete measurement system has been set up at the site and deemed to be operational, the following procedures should be completed before sampling is initiated.

7.1.1 *Leak Test.* Appropriate leak test procedures should be employed to verify the integrity of all components, sample lines, and connections. The following leak test procedure is suggested: For components upstream of the sample pump, attach the probe end of the sample line to a ma- nometer or vacuum gauge, start the pump and pull greater than 50 mm (2 in.) Hg vacuum, close off the pump outlet, and then stop the pump and ascertain that there is no leak for 1 minute. For components after the pump, apply a slight positive pressure and check for leaks by applying a liquid (detergent in water, for example) at each joint. Bubbling indicates the presence of a leak.

7.1.2 System Performance. Since the complete system is calibrated following each test, the precise calibration of each component is not critical. However, these components should be verified to be operating properly. This verification can be performed by observing the response of flowmeters or of the GC output to changes in flow rates or calibration gas concentrations and ascertaining the response to be within predicted limits. In any component, or if the complete system fails to respond in a normal and predictable manner, the source of the discrepancy should be identified and corrected before proceeding.

8. *Calibration.* Prior to any sampling run, calibrate the system using the following procedures. (If more than one run is performed during any 24-hour period, a calibration need not be performed prior to the second and any subsequent runs. The calibration must, however, be verified as prescribed in Section 10, after the last run made within the 24-hour period.)

8.1 General Considerations. This section outlines steps to be followed for use of the GC/FPD and the dilution system. The procedure does not include detailed instructions because the operation of these systems is complex, and it requires a understanding of the individual system being used. Each system should include a written operating manual describing in detail the operating procedures associated with each component in the measurement system. In addition, the operator should be familiar with the operating principles of the components; particularly the GC/FPD. The citations in the Bibliography at the end of this method are recommended for review for this purpose.

8.2 Calibration Procedure. Insert the permeation tubes into the tube chamber. Check the bath temperature to assure agreement with the calibration temperature of the tubes within ±0.1° C. Allow 24 hours for the tubes to equilibrate. Alternatively equilibration may be verified by injecting samples of calibration gas at 1-hour intervals. The permeation tubes can be assumed to have reached equilibrium when consecutive hourly samples agree within the precision limits of Section 4.1.

Vary the amount of air flowing over the tubes to produce the desired concentrations for calibrating the analytical and dilution systems. The air flow across the tubes must at all times exceed the flow requirement of the analytical systems. The concentration in parts per million generated by a tube containing a specific permeant can be calculated as follows:

$$C = K \frac{P_r}{ML}$$

Equation 16-1

where:

C=Concentration of permeant produced in ppm.
P_r=Permeation rate of the tube in μg/min.
M=Molecular weight of the permeant (g/g-mole).
L=Flow rate, l/min, of air over permeant @ 20° C, 760 mm Hg.
K=Gas constant at 20° C and 760 mm Hg=24.04 l/g mole.

8.3 Calibration of analysis system. Generate a series of three or more known concentrations spanning the linear range of the FPD (approximately 0.05 to 1.0 ppm) for each of the four major sulfur compounds. Bypassing the dilution system, inject these standards into the GC/FPD analyzers and monitor the responses. Three injects for each concentration must yield the precision described in Section 4.1. Failure to attain this precision is an indication of a problem in the calibration or analytical system. Any such problem must be identified and corrected before proceeding.

8.4 Calibration Curves. Plot the GC/FPD response in current (amperes) versus their causative concentrations in ppm on log-log coordinate graph paper for each sulfur compound. Alternatively, a least squares equation may be generated from the calibration data.

8.5 Calibration of Dilution System. Generate a known concentration of hydrogen sulfide using the permeation tube system. Adjust the flow rate of diluent air for the first dilution stage so that the desired level of dilution is approximated. Inject the diluted calibration gas into the GC/FPD system and monitor its response. Three injections for each dilution must yield the precision described in Section 4.1. Failure to attain this precision in this step is an indication of a problem in the dilution system. Any such problem must be identified and corrected before proceeding. Using the calibration data for H_2S (developed under 8.3) determine the diluted calibration gas concentration in ppm. Then calculate the dilution factor as the ratio of the calibration gas concentration before dilution to the diluted calibration gas concentration determined under this paragraph. Repeat this procedure for each stage of dilution required. Alternatively, the GC/FPD system may be calibrated by generating a series of three or more concentrations of each sulfur compound and diluting these samples before injecting them into the GC/FPD system. This data will then serve as the calibration data for the unknown samples and a separate determination of the dilution factor will not be necessary. However, the precision requirements of Section 4.1 are still applicable.

9. *Sampling and Analysis Procedure.*

9.1 Sampling. Insert the sampling probe into the test port making certain that no dilution air enters the stack through the port. Begin sampling and dilute the sample approximtely 9:1 using the dilution system. Note that the precise dilution factor is that which is determined in paragraph 8.5. Condition the entire system with sample for a minimum of 15 minutes prior to commencing analysis.

9.2 Analysis. Aliquots of diluted sample are injected into the GC/FPD analyzer for analysis.

9.2.1 Sample Run. A sample run is composed of 16 individual analyses (injects) performed over a period of not less than 3 hours or more than 6 hours.

9.2.2 Observation for Clogging of Probe. If reductions in sample concentrations are observed during a sample run that cannot be explained by process conditions, the sampling must be interrupted to determine if the sample probe is clogged with particulate matter. If the probe is found to be clogged, the test must be stopped and the results up to that point discarded. Testing may resume after cleaning the probe or replacing it with a clean one. After each run, the sample probe must be inspected and, if necessary, dismantled and cleaned.

10. *Post-Test Procedures.*

10.1 Sample Line Loss. A known concentration of hydrogen sulfide at the level of the applicable standard, ±20 percent, must be introduced into the sampling system at the opening of the probe in sufficient quantities to insure that there is an excess of sample which must be vented to the atmosphere. The sample must be transported through the entire sampling system to the measurement system in the normal manner. The resulting measured concentration should be compared to the known value to determine the sampling system loss. A sampling system loss of more than 20 percent is unacceptable. Sampling losses of 0-20 percent must be corrected for by dividing the resulting sample concentration by the fraction of recovery. The known gas sample may be generated using permeation tubes. Alternatively, cylinders of hydrogen sulfide mixed in air may be used provided they are traceable to permeation tubes. The optional pretest procedures provide a good guideline for determining if there are leaks in the sampling system.

10.2 Recalibration. After each run, or after a series of runs made within a 24-hour period, perform a partial recalibration using the procedures in Section 8. Only H_2S (or other permeant) need be used to recalibrate the GC/FPD analysis system (8.3) and the dilution system (8.5).

10.3 Determination of Calibration Drift. Compare the calibration curves obtained prior to the runs, to the calibration curves obtained under paragraph 10.1. The calibration drift should not exceed the limits set forth in paragraph 4.2. If the drift exceeds this limit, the intervening run or runs should be considered not valid. The tester, however, may instead have the option of choosing the calibration data set which would give the highest sample values.

11. *Calculations.*

11.1 Determine the concentrations of each reduced sulfur compound detected directly from the calibration curves. Alternatively, the concentrations may be calculated using the equation for the least square line.

11.2 Calculation of TRS. Total reduced sulfur will be determined for each anaylsis made by summing the concentrations of each reduced sulfur compound resolved during a given analysis.

$$TRS = \Sigma (H_2S, MeSH, DMS, 2DMDS)d$$

Equation 16-2

where:

TRS=Total reduced sulfur in ppm, wet basis.
H_2S=Hydrogen sulfide, ppm.
MeSH=Methyl mercaptan, ppm.
DMS=Dimethyl sulfide, ppm.
DMDS=Dimethyl disulfide, ppm.
d=Dilution factor, dimensionless.

11.3 Average TRS. The average TRS will be determined as follows:

$$\text{Average TRS} = \frac{\sum_{i=1}^{N} TRS_i}{N(1-B_{wo})}$$

Average TRS = Average total reduced suflur in ppm, dry basis.
TRS_i = Total reduced sulfur in ppm as determined by Equation 16-2.
N = Number of samples.
B_{wo} = Fraction of volume of water vapor in the gas stream as determined by method 4—Determination of Moisture in Stack Gases (36 FR 24887).

11.4 Average concentration of individual reduced sulfur compounds.

$$C = \frac{\sum_{i=1}^{N} S_i}{N}$$

Equation 16-3

where:

S_i = Concentration of any reduced sulfur compound from the ith sample injection, ppm.
C = Average concentration of any one of the reduced sulfur compounds for the entire run, ppm.
N = Number of injections in any run period.

12. *Example System.* Described below is a system utilized by EPA in gathering NSPS data. This system does not now reflect all the latest developments in equipment and column technology, but it does represent one system that has been demonstrated to work.

12.1 Apparatus.

12.1.1 Sampling System.

12.1.1.1 Probe. Figure 16-1 illustrates the probe used in lime kilns and other sources where significant amounts of particulate matter are present. the probe is designed with the deflector shield placed between the sample and the gas inlet holes and the glass wool plugs to reduce clogging of the filter and possible adsorption of sample gas. The exposed portion of the probe between the sampling port and the sample line is heated with heating tape.

12.1.1.2 Sample Line $\frac{3}{16}$ inch inside diameter Teflon tubing, heated to 120° C. This temperature is controlled by a thermostatic heater.

12.1.1.3 Sample Pump. Leakless Teflon coated diaphragm type or equivalent. The pump head is heated to 120° C by enclosing it in the sample dilution box (12.2.4 below).

12.1.2 Dilution System. A schematic diagram of the dynamic dilution system is given in Figure 16-2. The dilution system is constructed such that all sample contacts are made of inert materials. The dilution system which is heated to 120° C must be capable of a minimum of 9:1 dilution of sample. Equipment used in the dilution system is listed below:

12.1.2.1 Dilution Pump. Model A-150 Kohmyhr Teflon positive displacement type, nonadjustable 150 cc/min. ±2.0 percent, or equivalent, per dilution stage. A 9:1 dilution of sample is accomplished by combining 150 cc of sample with 1,350 cc of clean dry air as shown in Figure 16-2.

12.1.2.2 Valves. Three-way Teflon solenoid or manual type.

12.1.2.3 Tubing. Teflon tubing and fittings are used throughout from the sample probe to the GC/FPD to present an inert surface for sample gas.

12.1.2.4 Box. Insulated box, heated and maintained at 120° C, of sufficient dimensions to house dilution apparatus.

12.1.2.5 Flowmeters. Rotameters or equivalent to measure flow from 0 to 1500 ml/min ±1 percent per dilution stage.

12.1.3 Gas Chromatograph Columns. Two types of columns are used for separation of low and high molecular weight sulfur compounds:

12.1.3.1 Low Molecular Weight Sulfur Compounds Column (GC/FPD-1).

12.1.3.1 Separation Column. 11 m by 2.16 mm (36 ft by 0.085 in) inside diameter Teflon tubing packed with 30/60 mesh Teflon coated with 5 percent polyphenyl ether and 0.05 percent orthophosphoric acid, or equivalent (see Figure 16-3).

12.1.3.1.2 Stripper or Precolumn. 0.6 m by 2.16 mm (2 ft by 0.085 in) inside diameter Teflon tubing packed as in 5.3.1.

12.1.3.1.3 Sample Valve. Teflon 10-port gas sampling valve, equipped with a 10 ml sample loop, actuated by compressed air (Figure 16-3).

12.1.3.1.4 Oven. For containing sample valve, stripper column and separation column. The oven should be capable of maintaining an elevated temperature ranging from ambient to 100° C, constant within ±1° C.

12.1.3.1.5 Temperature Monitor. Thermocouple pyrometer to measure column oven, detector, and exhaust temperature ±1° C.

12.1.3.1.6 Flow System. Gas metering system to measure sample flow, hydrogen flow, and oxygen flow (and nitrogen carrier gas flow).

12.1.3.1.7 Detector. Flame photometric detector.

12.1.3.1.8 Electrometer. Capable of full scale amplification of linear ranges of 10^{-9} to 10^{-4} amperes full scale.

12.1.3.1.9 Power Supply. Capable of delivering up to 750 volts.

12.1.3.1.10 Recorder. Compatible with the output voltage range of the electrometer.

12.1.3.2 High Molecular Weight Compounds Column (GC/FPD-11).

12.1.3.2.1. Separation Column. 3.05 m by 2.16 mm (10 ft by 0.0885 in) inside diameter Teflon tubing packed with 30/60 mesh Teflon coated with 10 percent Triton X-305, or equivalent.

12.1.3.2.2 Sample Valve. Teflon 6-port gas sampling valve equipped with a 10 ml sample loop, actuated by compressed air (Figure 16-3).

12.1.3.2.3 Other Components. All components same as in 12.1.3.1.4 to 12.1.3.1.10.

12.1.4 Calibration. Permeation tube system (figure 16-4).

12.1.4.1 Tube Chamber. Glass chamber of sufficient dimensions to house permeation tubes.

12.1.4.2 Mass Flowmeters. Two mass flowmeters in the range 0-3 1/min. and 0-10 1/min. to measure air flow over permeation tubes at ±2 percent. These flowmeters shall be cross-calibrated at the beginning of each test. Using a convenient flow rate in the measuring range of both flowmeters, set and monitor the flow rate of gas over the permeation tubes. Injection of calibration gas generated at this flow rate as measured by one flowmeter followed by injection of calibration gas at the same flow rate as measured by the other flowmeter should agree within the specified precision limits. If they do not, then there is a problem with the mass flow measurement. Each mass flowmeter shall be calibrated prior to the first test with a wet test meter and thereafter, at least once each year.

12.1.4.3 Constant Temperature Bath. Capable of maintaining permeation tubes at certification temperature of 30° C. within ±0.1° C.

12.2 Reagents

12.2.1 Fuel. Hydrogen (H_2) prepurified grade or better.

12.2.2. Combustion Gas. Oxygen (O_2) research purity or better.

12.2.3 Carrier Gas. Nitrogen (N_2) prepurified grade or better.

12.2.4 Diluent. Air containing less than 50 ppb total sulfur compounds and less than 10 ppm each of moisture and total hydrocarbons, and filtered using MSA filters 46727 and 79030, or equivalent. Removal of sulfur compounds can be verified by injecting dilution air only, described in Section 8.3.

12.2.5 Compressed Air. 60 psig for GC valve actuation.

12.2.6 Calibrated Gases. Permeation tubes gravimetrically calibrated and certified at 30.0° C.

12.3 Operating Parameters.

12.3.1 Low-Molecular Weight Sulfur Compounds. The operating parameters for the GC/FPD system used for low molecular weight compounds are as follows: nitrogen carrier gas flow rate of 50 cc/min, exhaust temperature of 110° C, detector temperature of 105° C, oven temperature of 40° C, hydrogen flow rate of 80 cc/min, oxygen flow rate of 20 cc/min, and sample flow rate between 20 and 80 cc/min.

12.3.2 High-Molecular Weight Sulfur Compounds. The operating parameters for the GC/FPD system for high molecular weight compounds are the same as in 12.3.1 except: oven temperature of 70° C, and nitrogen carrier gas flow of 100 cc/min.

12.4 Analysis Procedure.

12.4.1 Analysis. Aliquots of diluted sample are injected simultaneously into both GC/FPD analyzers for analysis. GC/FPD-I is used to measure the low-molecular weight reduced sulfur compounds. The low molecular weight compounds include hydrogen sulfide, methyl mercaptan, and dimethyl sulfide. GC/FPD-II is used to resolve the high-molecular weight compound. The high-molecular weight compound is dimethyl disulfide.

12.4.1.1 Analysis of Low-Molecular Weight Sulfur Compounds. The sample valve is actuated for 3 minutes in which time an aliquot of diluted sample is injected into the stripper column and analytical column. The valve is then deactivated for approximately 12 minutes in which time, the analytical column continues to be foreflushed, the stripper column is backflushed, and the sample loop is refilled. Monitor the responses. The elution time for each compound will be determined during calibration.

12.4.1.2 Analysis of High-Molecular Weight Sulfur Compounds. The procedure is essentially the same as above except that no stripper column is needed.

13. *Bibliography.*

13.1 O'Keeffe, A. E. and G. C. Ortman. "Primary Standards for Trace Gas Analy-

sis." Analytical Chemical Journal, 38,760 (1966).

13.2 Stevens, R. K., A. E. O'Keeffe, and G. C. Ortman. "Absolute Calibration of a Flame Photometric Detector to Volatile Sulfur Compounds at Sub-Part-Per-Million Levels." Environmental Science and Technology, 3:7 (July, 1969).

13.3 Mulick, J. D., R. K. Stevens, and R. Baumgardner. "An Analytical System Designed to Measure Multiple Malodorous Compounds Related to Kraft Mill Activities." Presented at the 12th Conference on Methods in Air Pollution and Industrial Hygiene Studies, University of Southern California, Los Angeles, CA. April 6-8, 1971.

13.4 Devonald, R. H., R. S. Serenius, and A. D. McIntyre. "Evaluation of the Flame Photometric Detector for Analysis of Sulfur Compounds." Pulp and Paper Magazine of Canada, 73,3 (March, 1972).

13.5 Grimley, K. W., W. S. Smith, and R. M. Martin. "The Use of a Dynamic Dilution System in the Conditioning of Stack Gases for Automated Analysis by a Mobile Sampling Van." Presented at the 63rd Annual APCA Meeting in St. Louis, Mo. June 14-19, 1970.

13.6 General Reference. Standard Methods of Chemical Analysis Volume III A and B Instrumental Methods. Sixth Edition. Van Nostrand Reinhold Co.

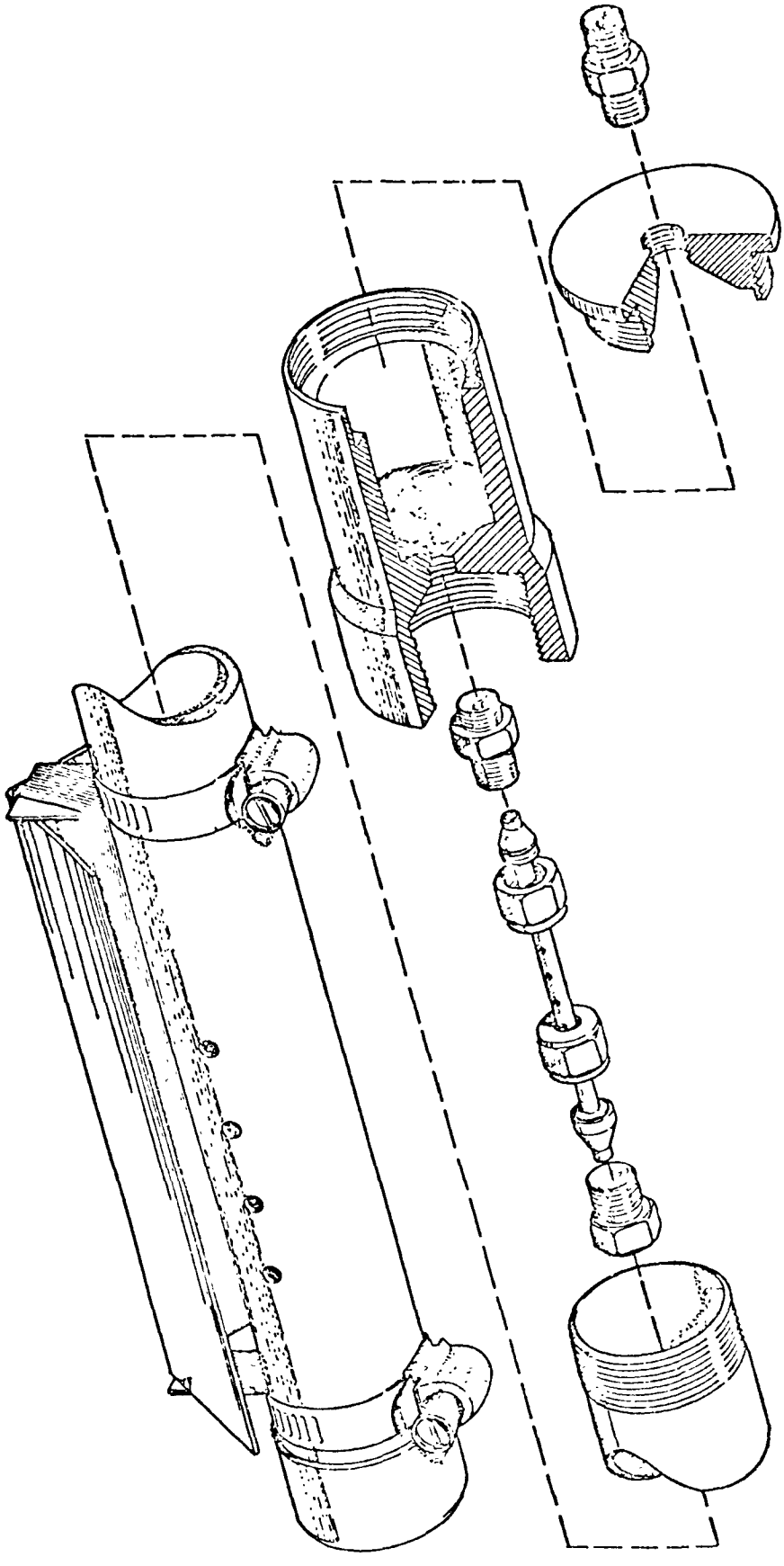


Figure 16-1. Probe used for sample gas containing high particulate loadings.

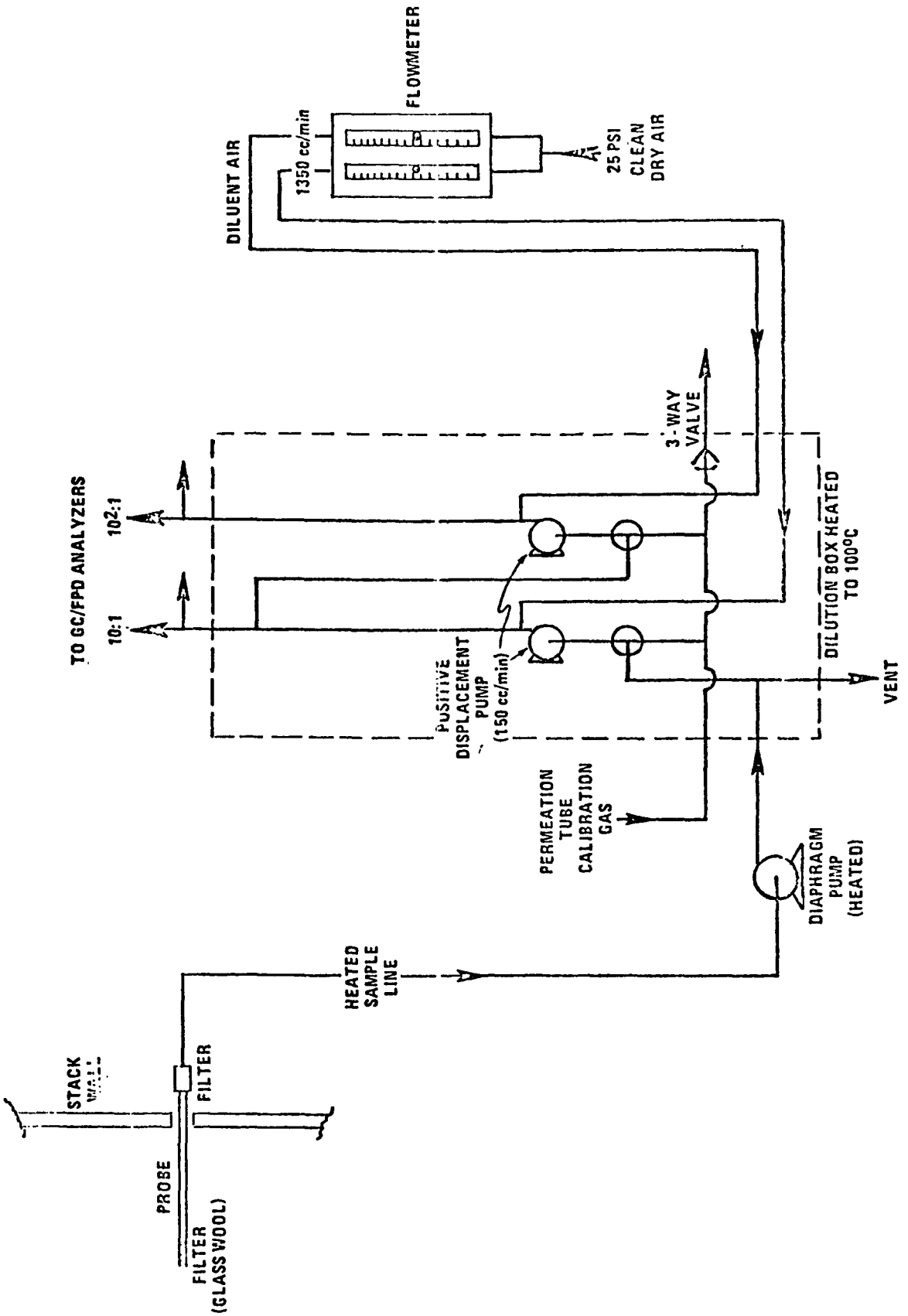


Figure 16-2. Sampling and dilution apparatus.

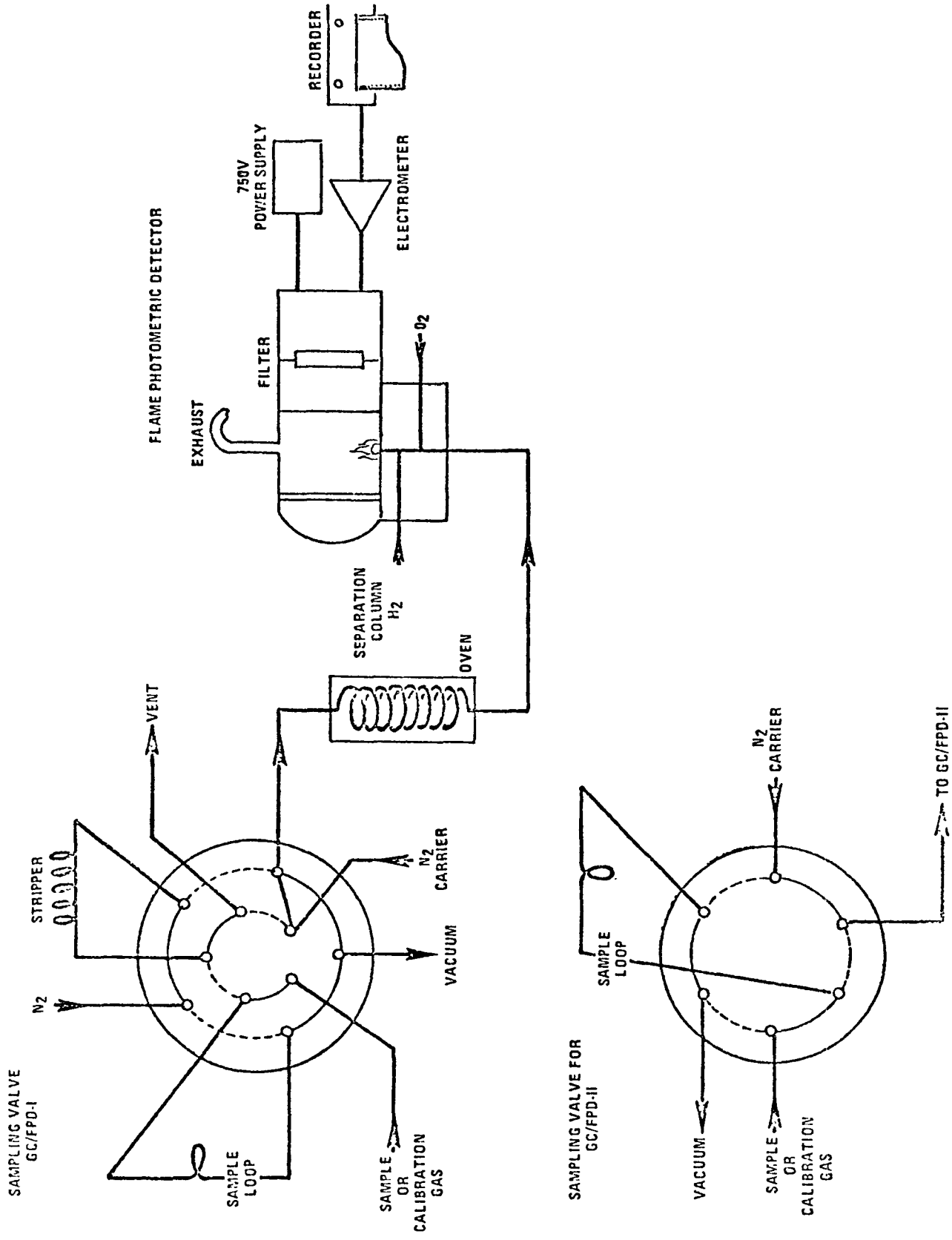


Figure 16-3. Gas chromatographic-flame photometric analyzers.

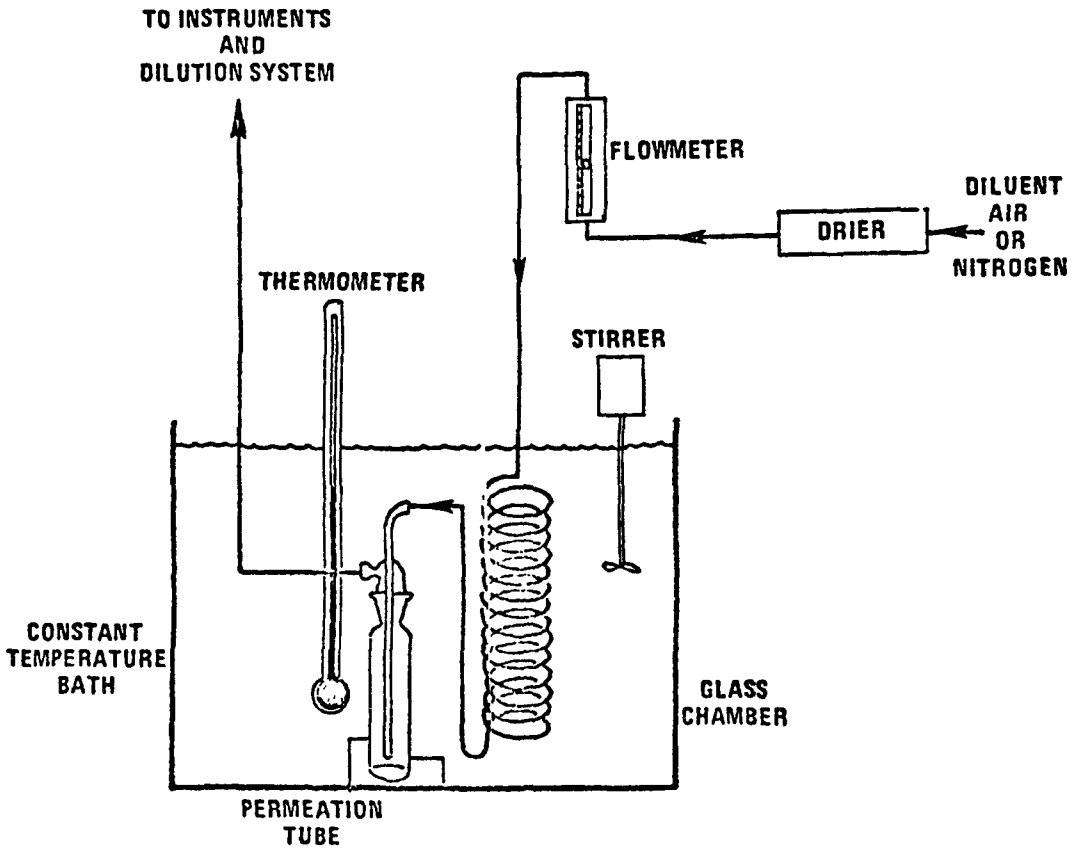


Figure 16-4. Apparatus for field calibration.

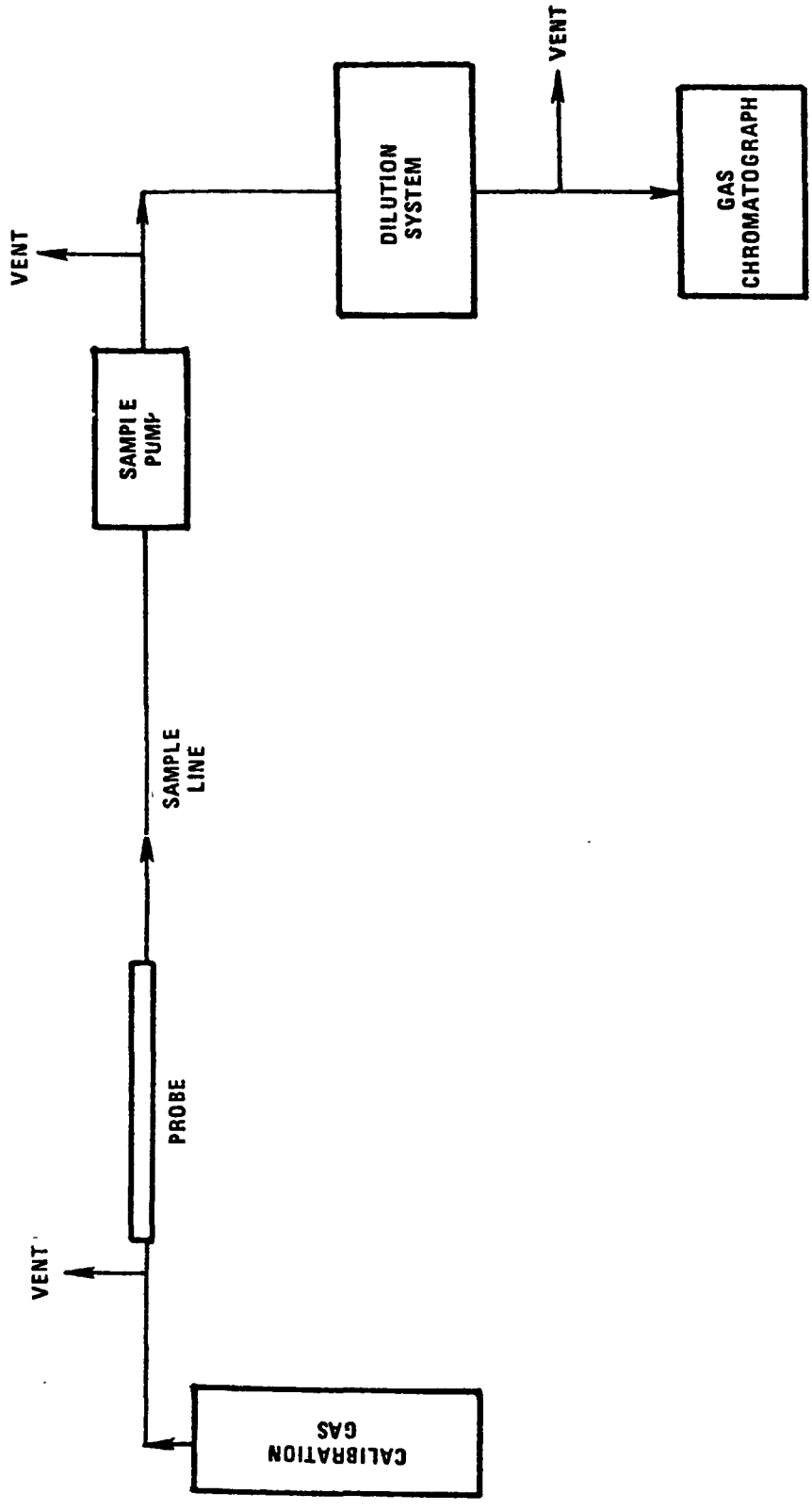


Figure 16- 5. Determination of sample line loss.

METHOD 17. DETERMINATION OF PARTICULATE EMISSIONS FROM STATIONARY SOURCES (IN-STACK FILTRATION METHOD)

Introduction

Particulate matter is not an absolute quantity; rather, it is a function of temperature and pressure. Therefore, to prevent variability in particulate matter emission regulations and/or associated test methods, the temperature and pressure at which particulate matter is to be measured must be carefully defined. Of the two variables (i.e., temperature and pressure), temperature has the greater effect upon the amount of particulate matter in an effluent gas stream; in most stationary source categories, the effect of pressure appears to be negligible.

In method 5, 250° F is established as a nominal reference temperature. Thus, where Method 5 is specified in an applicable subpart of the standards, particulate matter is defined with respect to temperature. In order to maintain a collection temperature of 250° F, Method 5 employs a heated glass sample probe and a heated filter holder. This equipment is somewhat cumbersome and requires care in its operation. Therefore, where particulate matter concentrations (over the normal range of temperature associated with a specified source category) are known to be independent of temperature, it is desirable to eliminate the glass probe and heating systems, and sample at stack temperature.

This method describes an in-stack sampling system and sampling procedures for use in such cases. It is intended to be used only when specified by an applicable subpart of the standards, and only within the applicable temperature limits (if specified), or when otherwise approved by the Administrator.

1. *Principle and Applicability.*

1.1 Principle. Particulate matter is withdrawn isokinetically from the source and collected on a glass fiber filter maintained at stack temperature. The particulate mass is determined gravimetrically after removal of uncombined water.

1.2 Applicability. This method applies to the determination of particulate emissions from stationary sources for determining compliance with new source performance standards, only when specifically provided for in an applicable subpart of the standards. This method is not applicable to stacks that contain liquid droplets or are saturated with water vapor. In addition, this method shall not be used as written if the projected cross-sectional area of the probe extension-filter holder assembly covers more than 5 percent of the stack cross-sectional area (see Section 4.1.2).

2. *Apparatus.*

2.1 Sampling Train. A schematic of the sampling train used in this method is shown in Figure 17-1. Construction details for many, but not all, of the train components are given in APTD-0581 (Citation 2 in Section 7); for changes from the APTD-0581 document and for allowable modifications to Figure 17-1, consult with the Administrator.

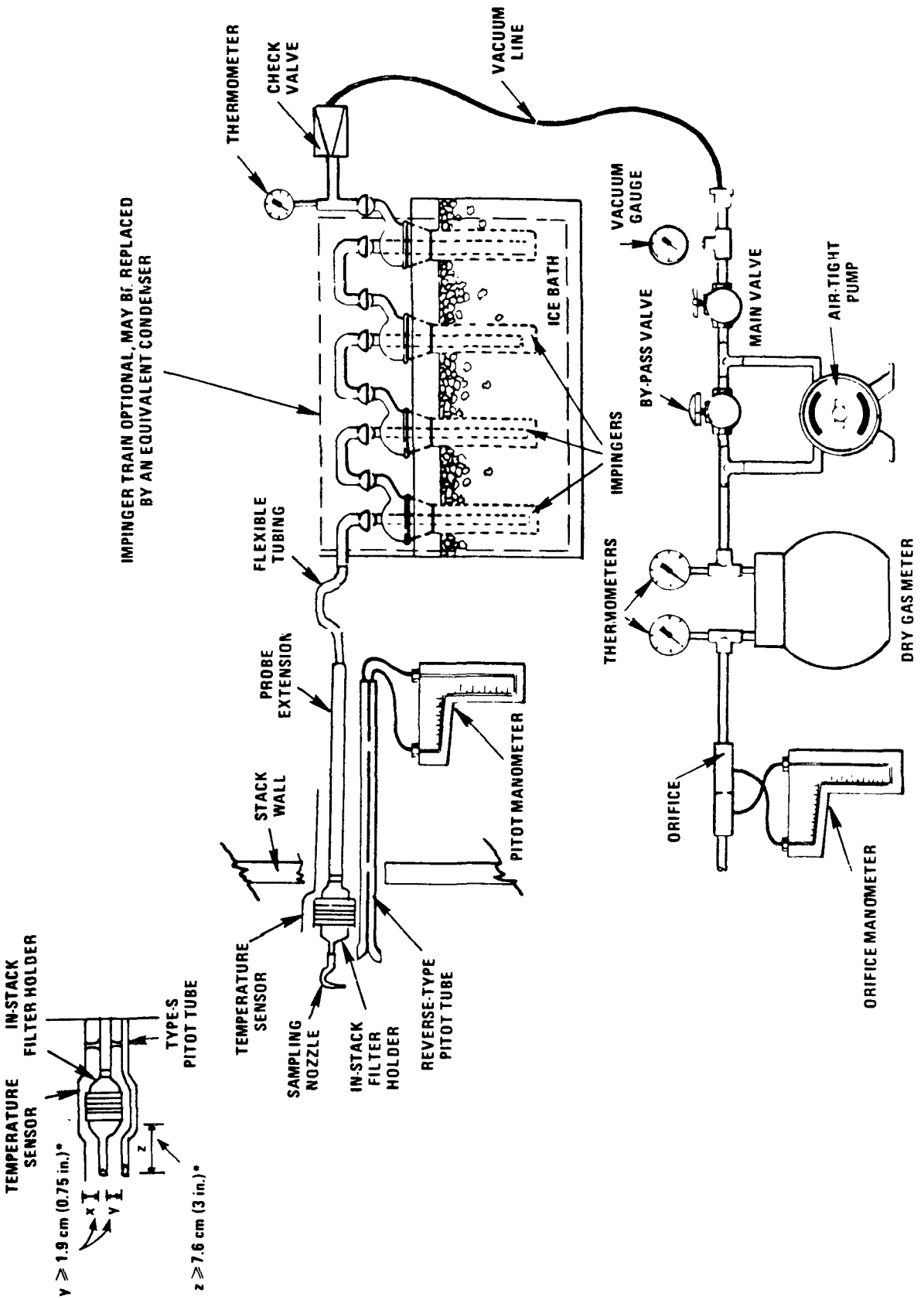


Figure 17-1. Particulate-Sampling Train, Equipped with In-Stack Filter.

The operating and maintenance procedures for many of the sampling train components are described in APTD-0576 (Citation 3 in Section 7). Since correct usage is important in obtaining valid results, all users should read the APTD-0576 document and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein. The sampling train consists of the following components:

2.1.1 Probe Nozzle. Stainless steel (316) or glass, with sharp, tapered leading edge. The angle of taper shall be 030° and the taper shall be on the outside to preserve a constant internal diameter. The probe nozzle shall be of the button-hook or elbow design, unless otherwise specified by the Administrator. If made of stainless steel, the nozzle shall be constructed from seamless tubing. Other materials of construction may be used subject to the approval of the Administrator.

A range of sizes suitable for isokinetic sampling should be available, e.g., 0.32 to 1.27 cm (⅛ to ½ in)—or larger if higher volume sampling trains are used—inside diameter (ID) nozzles in increments of 0.16 cm (1/16 in). Each nozzle shall be calibrated according to the procedures outlined in Section 5.1.

2.1.2 Filter Holder. The in-stack filter holder shall be constructed of borosilicate or quartz glass, or stainless steel; if a gasket is used, it shall be made of silicone rubber, Teflon, or stainless steel. Other holder and gasket materials may be used subject to the approval of the Administrator. The filter holder shall be designed to provide a positive seal against leakage from the outside or around the filter.

2.1.3 Probe Extension. Any suitable rigid probe extension may be used after the filter holder.

2.1.4 Pitot Tube. Type S, as described in Section 2.1 of Method 2, or other device approved by the Administrator; the pitot tube shall be attached to the probe extension to allow constant monitoring of the stack gas velocity (see Figure 17-1). The impact (high pressure) opening plane of the pitot tube shall be even with or above the nozzle entry plane during sampling (see Method 2, Figure 2-6b). It is recommended: (1) that the pitot tube have a known baseline coefficient, determined as outlined in Section 4 of Method 2; and (2) that this known coefficient be preserved by placing the pitot tube in an interference-free arrangement with respect to the sampling nozzle, filter holder, and temperature sensor (see Figure 17-1). Note that the 1.9 cm (0.75 in) free-space between the nozzle and pitot tube shown in Figure 17-1, is based on a 1.3 cm (0.5 in) ID nozzle. If the sampling train is designed for sampling at higher flow rates than that described in APTD-0581, thus necessitating the use of larger sized nozzles, the free-space shall be 1.9 cm (0.75 in) with the largest sized nozzle in place.

Source-sampling assemblies that do not meet the minimum spacing requirements of Figure 17-1 (or the equivalent of these requirements, e.g., Figure 2-7 of Method 2) may be used; however, the pitot tube coefficients of such assemblies shall be determined by calibration, using methods subject to the approval of the Administrator.

2.1.5 Differential Pressure Gauge. Inclined manometer or equivalent device (two), as described in Section 2.2 of Method 2. One manometer shall be used for velocity head (Δp) readings, and the other, for orifice differential pressure readings.

2.1.6 Condenser. It is recommended that the impinger system described in Method 5 be used to determine the moisture content of the stack gas. Alternatively, any system that allows measurement of both the water condensed and the moisture leaving the condenser, each to within 1 ml or 1 g, may be used. The moisture leaving the condenser can be measured either by: (1) monitoring the temperature and pressure at the exit of the condenser and using Dalton's law of partial pressures; or (2) passing the sample gas stream through a silica gel trap with exit gases kept below 20° C (68° F) and determining the weight gain.

Flexible tubing may be used between the probe extension and condenser. If means other than silica gel are used to determine the amount of moisture leaving the condenser, it is recommended that silica gel still be used between the condenser system and pump to prevent moisture condensation in the pump and metering devices and to avoid the need to make corrections for moisture in the metered volume.

2.1.7 Metering System. Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3° C (5.4° F), dry gas meter capable of measuring volume to within 2 percent, and related equipment, as shown in Figure 17-1. Other metering systems capable of maintaining sampling rates within 10 percent of isokinetic and of determining sample volumes to within 2 percent may be used, subject to the approval of the Administrator. When the metering system is used in conjunction with a pitot tube, the system shall enable checks of isokinetic rates.

Sampling trains utilizing metering systems designed for higher flow rates than that described in APTD-0581 or APTD-0576 may be used provided that the specifications of this method are met.

2.1.8 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.

2.1.9 Gas Density Determination Equipment. Temperature sensor and pressure gauge, as described in Sections 2.3 and 2.4 of Method 2, and gas analyzer, if necessary, as described in Method 3.

The temperature sensor shall be attached to either the pitot tube or to the probe extension, in a fixed configuration. If the temperature sensor is attached in the field; the sensor shall be placed in an interference-free arrangement with respect to the Type S pitot tube openings (as shown in Figure 17-1 or in Figure 2-7 of Method 2). Alternatively, the temperature sensor need not be attached to either the probe extension or pitot tube during sampling, provided that a difference of not more than 1 percent in the average velocity measurement is introduced. This alternative is subject to the approval of the Administrator.

2.2 Sample Recovery.

2.2.1 Probe Nozzle Brush. Nylon bristle brush with stainless steel wire handle. The brush shall be properly sized and shaped to brush out the probe nozzle.

2.2.2 Wash Bottles—Two. Glass wash bottles are recommended; polyethylene wash bottles may be used at the option of the tester. It is recommended that acetone not be stored in polyethylene bottles for longer than a month.

2.2.3 Glass Sample Storage Containers. Chemically resistant, borosilicate glass bottles, for acetone washes, 500 ml or 1000 ml. Screw cap liners shall either be rubber-backed Teflon or shall be constructed so as to be leak-free and resistant to chemical attack by acetone. (Narrow mouth glass bottles have been found to be less prone to leakage.) Alternatively, polyethylene bottles may be used.

2.2.4 Petri Dishes. For filter samples; glass or polyethylene, unless otherwise specified by the Administrator.

2.2.5 Graduated Cylinder and/or Balance. To measure condensed water to within 1 ml or 1 g. Graduated cylinders shall have subdivisions no greater than 2 ml. Most laboratory balances are capable of weighing to the nearest 0.5 g or less. Any of these balances is suitable for use here and in Section 2.3.4.

2.2.6 Plastic Storage Containers. Air tight containers to store silica gel.

2.2.7 Funnel and Rubber Policeman. To aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.

2.2.8 Funnel. Glass or polyethylene, to aid in sample recovery.

2.3 Analysis.

2.3.1 Glass Weighing Dishes.

2.3.2 Desiccator.

2.3.3 Analytical Balance. To measure to within 0.1 mg.

2.3.4 Balance. To measure to within 0.5 mg.

2.3.5 Beakers. 250 ml.

2.3.6 Hygrometer. To measure the relative humidity of the laboratory environment.

2.3.7 Temperature Gauge. To measure the temperature of the laboratory environment.

3. *Reagents.*

3.1 Sampling.

3.1.1 Filters. The in-stack filters shall be glass mats or thimble fiber filters, without organic binders, and shall exhibit at least 99.95 percent efficiency (00.05 percent penetration) on 0.3 micron dioctyl phthalate smoke particles. The filter efficiency tests shall be conducted in accordance with ASTM standard method D 2986-71. Test data from the supplier's quality control program are sufficient for this purpose.

3.1.2 Silica Gel. Indicating type, 6- to 16-mesh. If previously used, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to the approval of the Administrator.

3.1.3 Crushed Ice.

3.1.4 Stopcock Grease. Acetone-insoluble, heat-stable silicone grease. This is not necessary if screw-on connectors with Teflon sleeves, or similar, are used. Alternatively, other types of stopcock grease may be used, subject to the approval of the Administrator.

3.2 Sample Recovery. Acetone, reagent grade, 00.001 percent residue, in glass bottles. Acetone from metal containers generally has a high residue blank and should not be used. Sometimes, suppliers transfer acetone to glass bottles from metal containers. Thus, acetone blanks shall be run prior to field use and only acetone with low blank

values (00.001 percent) shall be used. In no case shall a blank value of greater than 0.001 percent of the weight of acetone used be subtracted from the sample weight.

3.3 Analysis.

3.3.1 Acetone. Same as 3.2.

3.3.2 Desiccant. Anhydrous calcium sulfate, indicating type. Alternatively, other types of desiccants may be used, subject to the approval of the Administrator.

4. *Procedure.*

4.1 Sampling. The complexity of this method is such that, in order to obtain reliable results, testers should be trained and experienced with the test procedures.

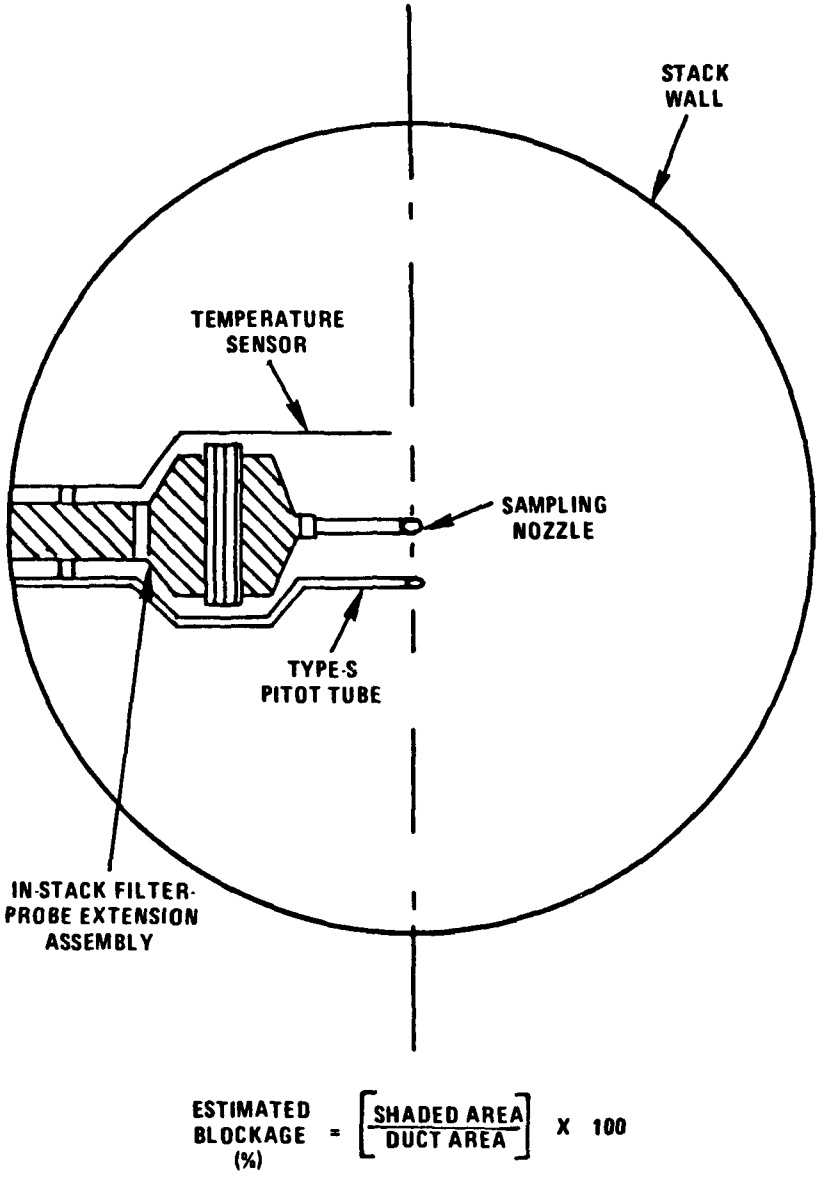
4.1.1 Pretest Preparation. All components shall be maintained and calibrated according to the procedure described in APTD-0576, unless otherwise specified herein.

Weigh several 200 to 300 g portions of silica gel in air-tight containers to the nearest 0.5 g. Record the total weight of the silica gel plus container, on each container. As an alternative, the silica gel need not be preweighed, but may be weighed directly in its impinger or sampling holder just prior to train assembly.

Check filters visually against light for irregularities and flaws or pinhole leaks. Label filters of the proper size on the back side near the edge using numbering machine ink. As an alternative, label the shipping containers (glass or plastic petri dishes) and keep the filters in these containers at all times except during sampling and weighing.

Desiccate the filters at 20±5.6° C (68±10° F) and ambient pressure for at least 24 hours and weigh at intervals of at least 6 hours to a constant weight, i.e., 00.5 mg change from previous weighing; record results to the nearest 0.1 mg. During each weighing the filter must not be exposed to the laboratory atmosphere for a period greater than 2 minutes and a relative humidity above 50 percent. Alternatively (unless otherwise specified by the Administrator), the filters may be oven dried at 105° C (220° F) for 2 to 3 hours, desiccated for 2 hours, and weighed. Procedures other than those described, which account for relative humidity effects, may be used, subject to the approval of the Administrator.

4.1.2 Preliminary Determinations. Select the sampling site and the minimum number of sampling points according to Method 1 or as specified by the Administrator. Make a projected-area model of the probe extension-filter holder assembly, with the pitot tube face openings positioned along the centerline of the stack, as shown in Figure 17-2. Calculate the estimated cross-section blockage, as shown in Figure 17-2. If the blockage exceeds 5 percent of the duct cross sectional area, the tester has the following options: (1) a suitable out-of-stack filtration method may be used instead of in-stack filtration; or (2) a special in-stack arrangement, in which the sampling and velocity measurement sites are separate, may be used; for details concerning this approach, consult with the Administrator (see also Citation 10 in Section 7). Determine the stack pressure, temperature, and the range of velocity heads using Method 2; it is recommended that a leak-check of the pitot lines (see Method 2, Section 3.1) be performed. Determine the moisture content using Approximation Method 4 or its alternatives for the purpose of making isokinetic sampling rate settings. Determine the stack gas dry molecular weight, as described in Method 2, Section 3.6; if integrated Method 3 sampling is used for molecular weight determination, the integrated bag sample shall be taken simultaneously with, and for the same total length of time as, the particular sample run.



$$\text{ESTIMATED BLOCKAGE (\%)} = \left[\frac{\text{SHADED AREA}}{\text{DUCT AREA}}\right] \times 100$$

Figure 17-2. Projected-area model of cross-section blockage (approximate average for a sample traverse) caused by an in-stack filter holder-probe extension assembly.

Select a nozzle size based on the range of velocity heads, such that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates. During the run, do not change the nozzle size. Ensure that the proper differential pressure gauge is chosen for the range of velocity heads encountered (see Section 2.2 of Method 2).

Select a probe extension length such that all traverse points can be sampled. For large stacks, consider sampling from opposite sides of the stack to reduce the length of probes.

Select a total sampling time greater than or equal to the minimum total sampling time specified in the test procedures for the specific industry such that (1) the sampling time per point is not less than 2 minutes (or some greater time interval if specified by the Administrator), and (2) the sample volume taken (corrected to standard conditions) will exceed the required minimum total gas sample volume. The latter is based on an approximate average sampling rate.

It is recommended that the number of minutes sampled at each point be an integer or an integer plus one-half minute, in order to avoid timekeeping errors.

In some circumstances, e.g., batch cycles, it may be necessary to sample for shorter times at the traverse points and to obtain smaller gas sample volumes. In these cases, the Administrator's approval must first be obtained.

4.1.3 Preparation of Collection Train. During preparation and assembly of the sampling train, keep all openings where contamination can occur covered until just prior to assembly or until sampling is about to begin.

If impingers are used to condense stack gas moisture, prepare them as follows: place 100 ml of water in each of the first two impingers, leave the third impinger empty, and transfer approximately 200 to 300 g of preweighed silica gel from its container to the fourth impinger. More silica gel may be used, but care should be taken to ensure that it is not entrained and carried out from the impinger during sampling. Place the container in a clean place for later use in the sample recovery. Alternatively, the weight of the silica gel plus impinger may be determined to the nearest 0.5 g and recorded.

If some means other than impingers is used to condense moisture, prepare the condenser (and, if appropriate, silica gel for condenser outlet) for use.

Using a tweezer or clean disposable surgical gloves, place a labeled (identified) and weighed filter in the filter holder. Be sure that the filter is properly centered and the gasket properly placed so as not to allow the sample gas stream to circumvent the filter. Check filter for tears after assembly is completed. Mark the probe extension with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point.

Assemble the train as in Figure 17-1, using a very light coat of silicone grease on all ground glass joints and greasing only the outer portion (see APTD-0576) to avoid possibility of contamination by the silicone grease. Place crushed ice around the impingers.

4.1.4 Leak Check Procedures.

4.1.4.1 Pretest Leak-Check. A pretest leak-check is recommended, but not required. If the tester opts to conduct the pretest leak-check, the following procedure shall be used.

After the sampling train has been assembled, plug the inlet to the probe nozzle with a material that will be able to withstand the stack temperature. Insert the filter holder into the stack and wait approximately 5 minutes (or longer, if necessary) to allow the system to come to equilibrium with the temperature of the stack gas stream. Turn on the pump and draw a vacuum of at least 380 mm Hg (15 in. Hg); note that a lower vacuum may be used, provided that it is not exceeded during the test. Determine the leakage rate. A leakage rate in excess of 4 percent of the average sampling rate or 0.00057 m³/min. (0.02 cfm), whichever is less, is unacceptable.

The following leak-check instructions for the sampling train described in APTD-0576 and APTD-0581 may be helpful. Start the pump with by-pass valve fully open and coarse adjust valve completely closed. Partially open the coarse adjust valve and slowly close the by-pass valve until the desired vacuum is reached. Do not reverse direction of by-pass valve. If the desired vacuum is exceeded, either leak-check at this higher vacuum or end the leak-check as shown below and start over.

When the leak-check is completed, first slowly remove the plug from the inlet to the probe nozzle and immediately turn off the vacuum pump. This prevents water from being forced backward and keeps silica gel from being entrained backward.

4.1.4.2 Leak-Checks During Sample Run. If, during the sampling run, a component (e.g., filter assembly or impinger) change becomes necessary, a leak-check shall be conducted immediately before the change is made. The leak-check shall be done according to the procedure outlined in Section 4.1.4.1 above, except that it shall be done at a vacuum equal to or greater than the maximum value recorded up to that point in the test. If the leakage rate is found to be no greater than 0.00057 m³/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction will need to be applied to the total volume of dry gas metered; if, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and plan to correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

Immediately after component changes, leak-checks are optional; if such leak-checks are done, the procedure outlined in Section 4.1.4.1 above shall be used.

4.1.4.3 Post-Test Leak-Check. A leak-check is mandatory at the conclusion of each sampling run. The leak-check shall be done in accordance with the procedures outlined in Section 4.1.4.1, except that it shall be conducted at a vacuum equal to or greater than the maximum value reached during the sampling run. If the leakage rate is found to be no greater than 0.00057 m³/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction need be applied to the total volume of dry gas metered. If, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

4.1.5 Particulate Train Operation. During the sampling run, maintain a sampling rate such that sampling is within 10 percent of true isokinetic, unless otherwise specified by the Administrator.

For each run, record the data required on the example data sheet shown in Figure 17-3. Be sure to record the initial dry gas meter reading. Record the dry gas meter readings at the beginning and end of each sampling time increment, when changes in flow rates are made, before and after each leak check, and when sampling is halted. Take other readings required by Figure 17-3 at least once at each sample point during each time increment and additional readings when significant changes (20 percent variation in velocity head readings) necessitate additional adjustments in flow rate. Level and zero the manometer. Because the manometer level and zero may drift due to vibrations and temperature changes, make periodic checks during the traverse.

PLANT _____

LOCATION _____

OPERATOR _____

DATE _____

RUN NO. _____

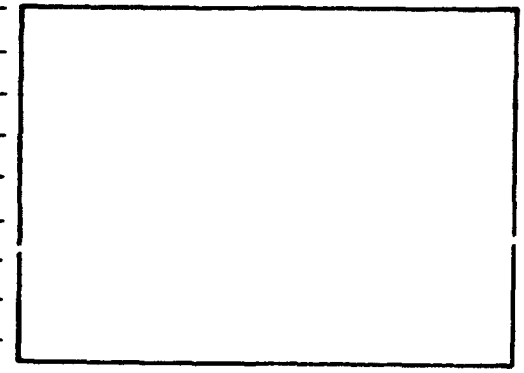
SAMPLE BOX NO. _____

METER BOX NO. _____

METER ΔH@ _____

C FACTOR _____

PITOT TUBE COEFFICIENT, Cp _____



SCHEMATIC OF STACK CROSS SECTION

BAROMETRIC PRESSURE _____

ASSUMED MOISTURE, % _____

PROBE EXTENSION LENGTH, m(ft.) _____

NOZZLE IDENTIFICATION NO. _____

AVERAGE CALIBRATED NOZZLE DIAMETER cm(in.) _____

FILTER NO. _____

LEAK RATE, m^3/min,(cfm) _____

STATIC PRESSURE, mm Hg (in. Hg) _____

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	VACUUM mm Hg (in. Hg)	STACK TEMPERATURE (T_S), °C (°F)	VELOCITY HEAD (ΔP_S), mm H_2O (in. H_2O)	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER, mm H_2O (in. H_2O)	GAS SAMPLE VOLUME, m^3 (ft^3)	GAS SAMPLE TEMPERATURE AT DRY GAS METER		TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °C (°F)
							INLET, °C (°F)	OUTLET, °C (°F)	
TOTAL							Avg	Avg	
AVERAGE							Avg		

Figure 17-3. Particulate field data.

Clean the portholes prior to the test run to minimize the chance of sampling the deposited material. To begin sampling, remove the nozzle cap and verify that the pitot tube and probe extension are properly positioned. Position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. Nomographs are available, which aid in the rapid adjustment to the isokinetic sampling rate without excessive computations. These nomographs are designed for use when the Type S pitot tube coefficient is 0.85 ± 0.02, and the stack gas equivalent density (dry molecular weight) is equal to 29 ± 4. APTD-0576 details the procedure for using the nomographs. If C_p and M_d are outside the above stated ranges, do not use the nomographs unless appropriate steps (see Citation 7 in Section 7) are taken to compensate for the deviations.

When the stack is under significant negative pressure (height of impinger stem), take care to close the coarse adjust valve before inserting the probe extension assembly into the stack to prevent water from being forced backward. If necessary, the pump may be turned on with the coarse adjust valve closed.

When the probe is in position, block off the openings around the probe and porthole to prevent unrepresentative dilution of the gas stream.

Traverse the stack cross section, as required by Method 1 or as specified by the Administrator, being careful not to bump the probe nozzle into the stack walls when sampling near the walls or when removing or inserting the probe extension through the portholes, to minimize chance of extracting deposited material.

During the test run, take appropriate steps (e.g., adding crushed ice to the impinger ice bath) to maintain a temperature of less than 20° C (68° F) at the condenser outlet; this will prevent excessive moisture losses. Also, periodically check the level and zero of the manometer.

If the pressure drop across the filter becomes too high, making isokinetic sampling difficult to maintain, the filter may be replaced in the midst of a sample run. It is recommended that another complete filter holder assembly be used rather than attempting to change the filter itself. Before a new filter holder is installed, conduct a leak check, as outlined in Section 4.1.4.2. The total particulate weight shall include the summation of all filter assembly catches.

A single train shall be used for the entire sample run, except in cases where simultaneous sampling is required in two or more separate ducts or at two or more different locations within the same duct, or, in cases where equipment failure necessitates a change of trains. In all other situations, the use of two or more trains will be subject to the approval of the Administrator. Note that when two or more trains are used, a separate analysis of the collected particulate from each train shall be performed, unless identical nozzle sizes were used on all trains, in which case the particulate catches from the individual trains may be combined and a single analysis performed.

At the end of the sample run, turn off the pump, remove the probe extension assembly from the stack, and record the final dry gas meter reading. Perform a leak-check, as outlined in Section 4.1.4.3. Also, leak-check the pitot lines as described in Section 3.1 of Method 2; the lines must pass this leak-check, in order to validate the velocity head data.

4.1.6 Calculation of Percent Isokinetic. Calculate percent isokinetic (see Section 6.11) to determine whether another test run should be made. If there is difficulty in maintaining isokinetic rates due to source conditions, consult with the Administrator for possible variance on the isokinetic rates.

4.2 Sample Recovery. Proper cleanup procedure begins as soon as the probe extension assembly is removed from the stack at the end of the sampling period. Allow the assembly to cool.

When the assembly can be safely handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it to prevent losing or gaining particulate matter. Do not cap off the probe tip tightly while the sampling train is cooling down as this would create a vacuum in the filter holder, forcing condenser water backward.

Before moving the sample train to the cleanup site, disconnect the filter holder-probe nozzle assembly from the probe extension; cap the open inlet of the probe extension. Be careful not to lose any condensate, if present. Remove the umbilical cord from the condenser outlet and cap the outlet. If a flexible line is used between the first impinger (or condenser) and the probe extension, disconnect the line at the probe extension and let any condensed water or liquid drain into the impingers or condenser. Disconnect the probe extension from the condenser; cap the probe extension outlet. After wiping off the silicone grease, cap off the condenser inlet. Ground glass stoppers, plastic caps, or serum caps (whichever are appropriate) may be used to close these openings.

Transfer both the filter holder-probe nozzle assembly and the condenser to the cleanup area. This area should be clean and protected from the wind so that the chances of contaminating or losing the sample will be minimized.

Save a portion of the acetone used for cleanup as a blank. Take 200 ml of this acetone directly from the wash bottle being used and place it in a glass sample container labeled "acetone blank."

Inspect the train prior to and during disassembly and note any abnormal conditions. Treat the samples as follows:

Container No. 1. Carefully remove the filter from the filter holder and place it in its identified petri dish container. Use a pair of tweezers and/or clean disposable surgical gloves to handle the filter. If it is necessary to fold the filter, do so such that the particulate cake is inside the fold. Carefully transfer to the petri dish any particulate matter and/or filter fibers which adhere to the filter holder gasket, by using a dry Nylon bristle brush and/or a sharp-edged blade. Seal the container.

Container No. 2. Taking care to see that dust on the outside of the probe nozzle or other exterior surfaces does not get into the sample, quantitatively recover particulate matter or any condensate from the probe nozzle, fitting, and front half of the filter holder by washing these components with acetone and placing the wash in a glass container. Distilled water may be used instead of acetone when approved by the Administrator and shall be used when specified by the Administrator; in these cases, save a water blank and follow Administrator's directions on analysis. Perform the acetone rinses as follows:

Carefully remove the probe nozzle and clean the inside surface by rinsing with acetone from a wash bottle and brushing with a Nylon bristle brush. Brush until acetone rinse shows no visible particles, after which make a final rinse of the inside surface with acetone.

Brush and rinse with acetone the inside parts of the fitting in a similar way until no visible particles remain. A funnel (glass or polyethylene) may be used to aid in transferring liquid washes to the container. Rinse the brush with acetone and quantitatively collect these washings in the sample container. Between sampling runs, keep brushes clean and protected from contamination.

After ensuring that all joints are wiped clean of silicone grease (if applicable), clean the inside of the front half of the filter holder by rubbing the surfaces with a Nylon bristle brush and rinsing with acetone. Rinse each surface three times or more if needed to remove visible particulate. Make final rinse of the brush and filter holder. After all acetone washings and particulate matter are collected in the sample container, tighten the lid on the sample container so that acetone will not leak out when it is shipped to the laboratory. Mark the height of the fluid level to determine whether or not leakage occurred during transport. Label the container to clearly identify its contents.

Container No. 3. If silica gel is used in the condenser system for mositure content determination, note the color of the gel to determine if it has been completely spent; make a notation of its condition. Transfer the silica gel back to its original container and seal. A funnel may make it easier to pour the silica gel without spilling, and a rubber policeman may be used as an aid in removing the silica gel. It is not necessary to remove the small amount of dust particles that may adhere to the walls and are difficult to remove. Since the gain in weight is to be used for moisture calculations, do not use any water or other liquids to transfer the silica gel. If a balance is available in the field, follow the procedure for Container No. 3 under "Analysis."

Condenser Water. Treat the condenser or impinger water as follows: make a notation of any color or film in the liquid catch. Measure the liquid volume to within ± 1 ml by using a graduated cylinder or, if a balance is available, determine the liquid weight to within ± 0.5 g. Record the total volume or weight of liquid present. This information is required to calculate the moisture content of the effluent gas. Discard the liquid after measuring and recording the volume or weight.

4.3 Analysis. Record the data required on the example sheet shown in Figure 17-4. Handle each sample container as follows:

Container No. 1. Leave the contents in the shipping container or transfer the filter and any loose particulate from the sample container to a tared glass weighing dish. Desiccate for 24 hours in a desiccator containing anhydrous calcium sulfate. Weigh to a constant weight and report the results to the nearest 0.1 mg. For purposes of this Section, 4.3, the term "constant weight" means a difference of no more than 0.5 mg or 1 percent of total weight less tare weight, whichever is greater, between two consecutive weighings, with no less than 6 hours of desiccation time between weighings.

Alternatively, the sample may be oven dried at the average stack temperature or

105° C (220° F), whichever is less, for 2 to 3 hours, cooled in the desiccator, and weighed to a constant weight, unless otherwise specified by the Administrator. The tester may also opt to oven dry the sample at the average stack temperature or 105° C (220° F), whichever is less, for 2 to 3 hours, weigh the sample, and use this weight as a final weight.

Plant _____

Date _____

Run No. _____

Filter No. _____

Amount liquid lost during transport _____

Acetone blank volume, ml _____

Acetone wash volume, ml _____

Acetone black concentration, mg/mg (equation 17-4) _____

Acetone wash blank, mg (equation 17-5) _____

CONTAINER NUMBER	WEIGHT OF PARTICULATE COLLECTED, mg		
	FINAL WEIGHT	TARE WEIGHT	WEIGHT GAIN
1			
2			
TOTAL			
		Less acetone blank	
		Weight of particulate matter	

	VOLUME OF LIQUID WATER COLLECTED		
	IMPINGER VOLUME, ml	SILICA GEL WEIGHT, g	
FINAL			
INITIAL			
LIQUID COLLECTED			
TOTAL VOLUME COLLECTED		g*	ml

* CONVERT WEIGHT OF WATER TO VOLUME BY DIVIDING TOTAL WEIGHT INCREASE BY DENSITY OF WATER (1g/ml).

$$\frac{\text{INCREASE, g}}{\text{1 g/ml}} = \text{VOLUME WATER, ml}$$

Figure 17-4. Analytical data.

Container No. 2. Note the level of liquid in the container and confirm on the analysis sheet whether or not leakage occurred during transport. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results. Measure the liquid in this container either volumetrically to ±1 ml or gravimetrically to ±0.5 g. Transfer the contents to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

Container No. 3. This step may be conducted in the field. Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g using a balance.

"Acetone Blank" Container. Measure acetone in this container either volumetrically or gravimetrically. Transfer the acetone to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

NOTE.—At the option of the tester, the contents of Container No. 2 as well as the acetone blank container may be evaporated at temperatures higher than ambient. If evaporation is done at an elevated temperature, the temperature must be below the boiling point of the solvent; also, to prevent "bumping," the evaporation process must be closely supervised, and the contents of the beaker must be swirled occasionally to maintain an even temperature. Use extreme care, as acetone is highly flammable and has a low flash point.

5. *Calibration.* Maintain a laboratory log of all calibrations.

5.1 Probe Nozzle. Probe nozzles shall be calibrated before their initial use in the field. Using a micrometer, measure the inside diameter of the nozzle to the nearest 0.025 mm (0.001 in.). Make three separate measurements using different diameters each time, and obtain the average of the measurements. The difference between the high and low numbers shall not exceed 0.1 mm (0.004 in.). When nozzles become nicked, dented, or corroded, they shall be reshaped, sharpened, and recalibrated before use. Each nozzle shall be permanently and uniquely identified.

5.2 Pitot Tube. If the pitot tube is placed in an interference-free arrangement with respect to the other probe assembly components, its baseline (isolated tube) coefficient shall be determined as outlined in Section 4 of Method 2. If the probe assembly is not interference-free, the pitot tube assembly coefficient shall be determined by calibration, using methods subject to the approval of the Administrator.

5.3 Metering System. Before its initial use in the field, the metering system shall be calibrated according to the procedure outlined in APTD-0576. Instead of physically adjusting the dry gas meter dial readings to correspond to the wet test meter readings, calibration factors may be used to mathematically correct the gas meter dial readings to the proper values.

Before calibrating the metering system, it is suggested that a leak-check be conducted. For metering systems having diaphragm pumps, the normal leak-check procedure will not detect leakages within the pump. For these cases the following leak-check procedure is suggested: make a 10-minute calibration run at 0.00057 m^3/min (0.02 cfm); at the end of the run, take the difference of the measured wet test meter and dry gas meter volumes; divide the difference by 10, to get the leak rate. The leak rate should not exceed 0.00057 m^3/min (0.02 cfm).

After each field use, the calibration of the metering system shall be checked by performing three calibration runs at a single, intermediate orifice setting (based on the previous field test), with the vacuum set at the maximum value reached during the test series. To adjust the vacuum, insert a valve between the wet test meter and the inlet of the metering system. Calculate the average value of the calibration factor. If the calibration has changed by more than 5 percent, recalibrate the meter over the full range of orifice settings, as outlined in APTD-0576.

Alternative procedures, e.g., using the orifice meter coefficients, may be used, subject to the approval of the Administrator.

NOTE.—If the dry gas meter coefficient values obtained before and after a test series differ by more than 5 percent, the test series shall either be voided, or calculations for the test series shall be performed using whichever meter coefficient value (i.e., before or after) gives the lower value of total sample volume.

5.4 Temperature Gauges. Use the procedure in Section 4.3 of Method 2 to calibrate in-stack temperature gauges. Dial thermometers, such as are used for the dry gas meter and condenser outlet, shall be calibrated against mercury-in-glass thermometers.

5.5 Leak Check of Metering System Shown in Figure 17-1. That portion of the sampling train from the pump to the orifice meter should be leak checked prior to initial use and after each shipment. Leakage after the pump will result in less volume being recorded than is actually sampled. The following procedure is suggested (see Figure 17-5). Close the main valve on the meter box. Insert a one-hole rubber stopper with rubber tubing attached into the orifice exhaust pipe. Disconnect and vent the low side of the orifice manometer. Close off the low side orifice tap. Pressurize the system to 13 to 18 cm (5 to 7 in.) water column by blowing into the rubber tubing. Pinch off the tubing and observe the manometer for one minute. A loss of pressure on the manometer indicates a leak in the meter box; leaks, if present, must be corrected.

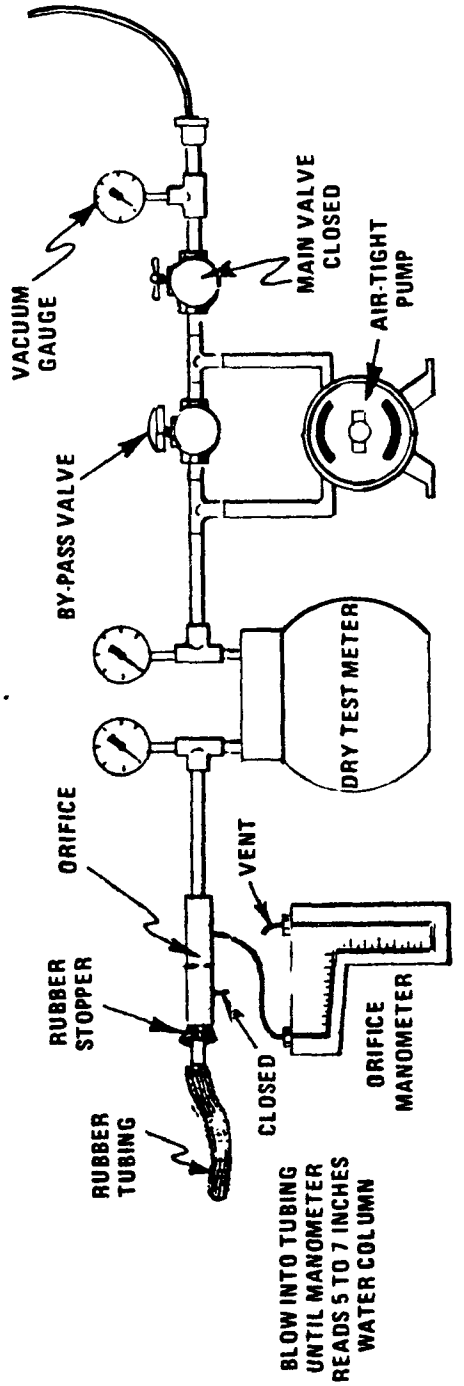


Figure 17-5. Leak check of meter box.

5.6 Barometer. Calibrate against a mercury barometer.

6. *Calculations.* Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after the final calculation. Other forms of the equations may be used as long as they give equivalent results.

6.1 Nomenclature.

A_n = Cross-sectional area of nozzle, m^2 (ft^2).
B_{ws} = Water vapor in the gas stream, proportion by volume.
C_a = Acetone blank residue concentration, mg/g.
c_s = Concentration of particulate matter in stack gas, dry basis, corrected to standard conditions, g/dscm (g/dscf).
I = Percent of isokinetic sampling
L_a = Maximum acceptable leakage rate for either a pretest leak check or for a leak check following a component change; equal to 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate, whichever is less.
L_i = Individual leakage rate observed during the leak check conducted prior to the "ith" component change (i = 1, 2, 3 . . . n), m^3/min (cfm).
L_p = Leakage rate observed during the post-test leak check, m^3/min (cfm).
m_n = Total amount of particulate matter collected, mg.
M_w = Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).
m_a = Mass of residue of acetone after evaporation, mg.
P_{bar} = Barometric pressure at the sampling site, mm Hg (in. Hg).
P_s = Absolute stack gas pressure, mm Hg (in. Hg).
P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).
R = Ideal gas constant, 0.06236 mm Hg-m^3/°K-g-mole (21.85 in. Hg-ft^3/°R-lb-mole).
T_m = Absolute average dry gas meter temperature (see Figure 17-3), °K (°R).
T_s = Absolute average stack gas temperature (see Figure 17-3), °K (°R).
T_{std} = Standard absolute temperature, 293°K (528°R).
V_a = Volume of acetone blank, ml.
V_{aw} = Volume of acetone used in wash, ml.
V_{lc} = Total volume of liquid collected in impingers and silica gel (see Figure 17-4), ml.
V_m = Volume of gas sample as measured by dry gas meter, dcm (dcf).
$V_{m(std)}$ = Volume of gas sample measured by the dry gas meter, corrected to standard conditions, dscm (dscf).
$V_{w(std)}$ = Volume of water vapor in the gas sample, corrected to standard conditions, scm (scf).
v_s = Stack gas velocity, calculated by Method 2, Equation 2-9, using data obtained from Method 17, m/sec (ft/sec).
W_a = Weight of residue in acetone wash, mg.
Y = Dry gas meter calibration coefficient.
ΔH = Average pressure differential across the orifice meter (see Figure 17-3), mm H_2O (in. H_2O).
ρ_a = Density of acetone, mg/ml (see label on bottle).
ρ_w = Density of water, 0.9982 g/ml (0.002201 lb/ml).
θ = Total sampling time, min.
θ_1 = Sampling time interval, from the beginning of a run until the first component change, min.
θ_i = Sampling time interval, between two successive component changes, beginning with the interval between the first and second changes, min.
θ_p = Sampling time interval, from the final (n^{th}) component change until the end of the sampling run, min.
13.6 = Specific gravity of mercury.
60 = Sec/min.
100 = Conversion to percent.

6.2 Average dry gas meter temperature and average orifice pressure drop. See data sheet (Figure 17-3).

6.3 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20° C, 760 mm Hg or 68° F, 29.92 in. Hg) by using Equation 17-1.

$$V_{m(std)} = V_m Y \left(\frac{T_{std}}{T_m}\right)\left[\frac{P_{bar} + \frac{\Delta H}{13.6}}{P_{std}}\right] = K_1 V_m Y \frac{P_{bar} + (\Delta H/13.6)}{T_m}$$

Equation 17-1

where:

K_1 = 0.3858° K/mm Hg for metric units; 17.64° R/in. Hg for English units.

NOTE.—Equation 17-1 can be used as written unless the leakage rate observed during any of the mandatory leak checks (i.e., the post-test leak check or leak checks conducted prior to component changes) exceeds L_a. If L_p or L_i exceeds L_a, Equation 17-1 must be modified as follows:

(a) Case I. No component changes made during sampling run. In this case, replace V_m in Equation 17-1 with the expression:

$$[V_m - (L_p - L_a)\theta]$$

(b) Case II. One or more component changes made during the sampling run. In this case, replace V_m in Equation 17-1 by the expression:

$$\left[V_m - (L_1 - L_a)\theta_1 - \sum_{i=2}^{n} (L_i - L_a)\theta_i - (L_p - L_a)\theta_p\right]$$

and substitute only for those leakage rates (L_i or L_p) which exceed L_a.

6.4 Volume of water vapor.

$$V_{w(std)} = V_{lc}\left(\frac{\rho_w}{M_w}\right)\left(\frac{RT_{std}}{P_{std}}\right) = K_2 V_{lc}$$

Equation 17-2

where:

K_2 = 0.001333 m^3/ml for metric units; 0.04707 ft^3/ml for English units.

6.5 Moisture Content.

$$B_{ws} = \frac{V_{w(std)}}{V_{m(std)} + V_{w(std)}}$$

Equation 17-3

6.6 Acetone Blank Concentration.

$$C_a = \frac{m_a}{V_a \rho_a}$$

Equation 17-4

6.7 Acetone Wash Blank.

$$W_a = C_a V_{aw} \rho_a$$

Equation 17-5

6.8 Total Particulate Weight. Determine the total particulate catch from the sum of the weights obtained from containers 1 and 2 less the acetone blank (see Figure 17-4).

NOTE.—Refer to Section 4.1.5 to assist in calculation of results involving two or more filter assemblies or two or more sampling trains.

6.9 Particulate Concentration.

$$c_s = (0.001\ g/mg)(m_n/V_{m(std)})$$

Equation 17-6

6.10 Conversion Factors:

From	To	Multiply by
scf	m^3	0.02832
g/ft^3	gr/ft^3	15 43
g/ft^3	lb/ft^3	2.205×10^{-3}
g/ft^3	g/m^3	35.31

6.11 Isokinetic Variation.

6.11.1 Calculation from Raw Data.

$$I = \frac{100\ T_s\ [K_3 V_{lc} + (V_m Y/T_m)\ (P_{bar} + \Delta H/13.6)]}{60\ \theta v_s\ P_s\ A_n}$$

Equation 17-7

where:

K_3 = 0.003454 mm Hg-m^3/ml-°K for metric units; 0.002669 in. Hg-ft^3/ml-°R for English units.

6.11.2 Calculation from Intermediate Values.

$$I = \frac{T_s\ V_{m(std)} P_{std}\ 100}{T_{std}\ v_s\ \theta\ A_n\ P_s\ 60\ (1-B_{ws})} = K_4 \frac{T_s\ V_{m(std)}}{P_s\ v_s\ A_n\ \theta\ (1-B_{ws})}$$

Equation 17-8

where:

K_4 = 4.320 for metric units; 0.09450 for English units.

6.12 Acceptable Results. If 90 percent 0I0110 percent, the results are acceptable. If the results are low in comparison to the standard and I is beyond the acceptable range, or, if I is less than 90 percent, the Administrator may opt to accept the results. Use Citation 4 in Section 7 to make judgments. Otherwise, reject the results and repeat the test.

7. *Bibliography.*

1. Addendum to Specifications for Incinerator Testing at Federal Facilities. PHS, NCAPC. December 6, 1967.

2. Martin, Robert M., Construction Details of Isokinetic Source-Sampling Equipment. Environmental Protection Agency. Research Triangle Park, N.C. APTD-0581. April, 1971.

3. Rom, Jerome J., Maintenance, Calibration, and Operation of Isokinetic Source-Sampling Equipment. Environmental Protection Agency. Research Triangle Park, N.C. APTD-0576. March, 1972.

4. Smith, W. S., R. T. Shigehara, and W. F. Todd. A Method of Interpreting Stack Sampling Data. Paper Presented at the 63rd Annual Meeting of the Air Pollution Control Association, St. Louis, Mo. June 14-19, 1970.

5. Smith, W. S., et al., Stack Gas Sampling Improved and Simplified with New Equipment. APCA Paper No. 67-119. 1967.

6. Specifications for Incinerator Testing at Federal Facilities. PHS, NCAPC. 1967.

7. Shigehara, R. T., Adjustments in the EPA Nomograph for Different Pitot Tube Coefficients and Dry Molecular Weights. Stack Sampling News 2:4-11. October, 1974.

8. Vollaro, R. F., A Survey of Commercially Available Instrumentation for the Measurement of Low-Range Gas Velocities. U.S. Environmental Protection Agency, Emission Measurement Branch. Research Triangle Park, N.C. November, 1976 (unpublished paper).

9. Annual Book of ASTM Standards. Part 26. Gaseous Fuels; Coal and Coke; Atmospheric Analysis. American Society for Testing and Materials. Philadelphia, Pa. 1974. pp. 617-622.

10. Vollaro, R. F., Recommended Procedure for Sample Traverses in Ducts Smaller than 12 Inches in Diameter. U.S. Environmental Protection Agency, Emission Measurement Branch. Research Triangle Park, N.C. November, 1976.

[FR Doc. 78-4795 Filed 2-22-78; 8:45 am]

Title 40—Protection of Environment

[FRL 848-2]

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

Revision of Authority Citations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action amends the authority citiations for Standards of Performance for New Stationary Sources and National Emission Stantards for Hazardous Pollutants. The amendment adopts the redesignation of classification numbers as changed in the 1977 amendments to the Clean Air Act. As amended, the Act formerly classified to 42 U.S.C. 1857 et seq. has been transferred and is now classified to 42 U.S.C. 7401 et seq.

EFFECTIVE DATE: March 3, 1978.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711 telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: This action is being taken in accordance with the requirements of 1 CFR 21.43 and is authorized under section 301(a) of the Clean Air Act, as amended, 42 U.S.C. 7601(a). Because the amendments are clerical in nature and affect no substantive rights or requirements, the Administrator finds it unnecessary to propose and invite public comment.

Dated: February 24, 1978.

DOUGLAS M. COSTLE,
Administrator.

Parts 60 and 61 of Chapter I, Title 40 of the Code of Federal Regulations are revised as follows:

1. The authority citation following the table of sections in Part 60 is revised to read as follows:

AUTHORITY: Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)), unless otherwise noted.

§§ 60.10 and 60.24 [Amended]

2. Following §§ 60.10 and 60.24(g) the following authority citation is added:

(Sec. 116 of the Clean Air Act as amended (42 U.S.C. 7416)).

§§ 60.7, 60.8, 60.9, 60.11, 60.13, 60.45, 60.46, 60.53, 60.54, 60.63, 60.64, 60.73, 60.74, 60.84, 60.85, 60.93, 60.105, 60.106, 60.113, 60.123, 60.133, 60.144, 60.153, 60.154, 60.165, 60.166, 60.175, 60.176, 60.185, 60.186, 60.194, 60.195, 60.203, 60.204, 60.213, 60.214, 60.223, 60.224, 60.233, 60.234, 60.243, 60.244, 60.253, 60.254, 60.264, 60.265, 60.266, 60.273, 60.274, 60.275, and Appendices A, B, C, and D [Amended]

3. The following authority citation is added to the above sections and appendices:

(Sec. 114, Clean Air Act is amended (42 U.S.C. 7414)).

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Lignite-Fired Steam Generators

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This final rule establishes standards of performance for new or modified lignite-fired steam generators with heat input rates greater than 73 megawatts (250 million Btu per hour) and limits emissions of nitrogen oxides to 260 ng/J of heat input except that 340 ng/J of heat input is allowed from cyclone-fired units which are fired with lignite mined in North Dakota, South Dakota, or Montana. Steam generators contribute significantly to air pollution, and the intended effect of this final rule is to require new steam generators which burn lignite to use the best control system for reducing emissions of nitrogen oxides.

EFFECTIVE DATE: March 7, 1978.

ADDRESSES: The "Standards Support and Environmental Impact Statement (SSEIS), Volume 2: Promulgated Standards of Performance for Lignite-Fired Steam Generators" (EPA-450/2-76-030b) may be obtained by writing the U.S. EPA Library (MD-35), Research Triangle Park, N.C. 27711. Volume 1 of the SSEIS, "Proposed Standards of Performance for Lignite-Fired Steam Generators" (EPA-450/2-76-030a), is also available at the same address. Please specify both the title and EPA number of the document desired. These documents and all public comments may be inspected at the Public Information Reference Unit (EPA Library), Room 2922, 401 M Street SW., Washington, D.C.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: On December 23, 1971 (36 FR 24877), EPA established under Subpart D of 40 CFR Part 60 standards of performance for new steam generators with heat input rates greater than 73 megawatts (250 million Btu per hour). Steam generators which burn lignitie were exempted from the emission standards for nitrogen oxides (NO_x) because too little operating experience was available to adequately characterize NO_x emissions. (Lignite-fired steam generators were not exempted from the standards for sulfur oxides and particulate matter, however.) Since 1971, EPA has gathered additional information on lignite-fired facilities, and on December 22, 1976 (41 FR 55791), the Agency proposed to amend Subpart D by establishing a standard of performance of 260 nanograms per joule (ng/J) of heat input (0.6 pound per million Btu) for NO_x emissions from new lignite-fired steam generators. Supporting information for the proposed standard was published in Volume 1 of the SSEIS for lignite-fired steam generators. After reviewing issues raised during the public comment period which followed the proposal, EPA decided to promulgate standards which will permit the limited use of cyclone-fired facilities to burn lignite mined in North Dakota, South Dakota, and Montana (which causes severe fouling and slagging in pulverized-fired units). Supporting information for these final standards of performance appears in Volume 2 of the SSEIS.

Final Standards

NO_x emissions from lignite-fired steam generators are limited to 260 ng/J of heat in put (0.6 lb/10^6 Btu) except that 340 ng/J (0.8 lb/10^6 Btu) is allowed from cyclone-fired steam generators burning lignite mined in North Dakota, South Dakota, and Montana. Both standards apply only to boilers which burn lignite, with heat input rates greater than 73 megawatts (250 million Btu per hour), and for which construction or modification began after December 21, 1976.

Rationale for Final Standards

The NO_x standard originally proposed by EPA, 260 ng/J, may have prevented the use of cyclone-fired boilers, since it has not been demonstrated that emisisons from these units can be consistently controlled to levels below 260 ng/J. During the public comment period, several commenters argued that the utilization of cyclone-fired boilers is necessary to overcome the serious fouling and slagging problems which develop whenever the sodium content of the lignite burned exceeds about 5 percent, by weight. These high sodium content reserves are believed to be widespread, especially in North Dakota, and the utilities claim that their low sodium content reserves are being rapidly depleted. The commenters said that cyclones have inherently lower fouling and slagging rates than other large boiler designs because much less ash is carried through the boiler convective passes. In addition, they contended that in the Dakotas there has actually been very little operating experience with pulverized-fired boilers, the alternative to large cyclones, and it is doubtful that these units can burn high sodium lignite without experiencing severe problems. Thus, the commenters concluded that the proposed standard might restrict the use of valuable resources of high sodium lignite fuel by prohibiting the utilization of cyclone-fired boilers. The commenters also argued that the proposed standard would place an economic burden on the electirc power utilities which burn lignite by limiting competitive bidding for new boilers.

EPA agrees that at present there is too little operating experience with pulverized- or cyclone-fired boilers to be able to predict their reliability when burning high sodium lignite. Furthermore, the Agency does not want to establish a standard which might inhibit future efforts to find a successful way to burn this troublesome fuel. Consequently, EPA has established a separate nitrogen oxides emission standard of 340 ng/J (0.8 lb/10^6 Btu) for new cyclone-fired boilers which burn North Dakota, South Dakota, or Montana lignite. This standard will permit the limited utlization of cyclone-fired boilers and assure the continued use of our country's abundant resources of lignite. Lignite mined in Texas, the only other known major lignite formation, generally has low sodium content and has been successfully burned in pulverized-fired units for years. The standard is supported by emission test data and other information contained in Volume I of the SSEIS. Nitrogen oxides emissions from pulverized-fired boilers will be limited to 260 ng/J (0.6 lb/10^6 Btu), as originally proposed.

Cyclone-fired boilers could account for 10 to 20 percent of all new lignite-fired steam generators, based on EPA estimates of lignite consumption for the year 1980. EPA estimates that NO_x emissions from new cyclone-fired boilers may be reduced by as much as 20 percent as a result of the standard. The combined effect of both standards will be to reduce total NO_x emissions from all new boilers which burn lignite by about 25 percent.

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements). State implementation plans (SIPs) approved or promulgated under section 110 of the Act, on the other hand, must provide for the attainment and maintenance of national ambient air quality standards (NAAQS) designed to protect public health and welfare. For that purpose, SIPs must in some cases require greater emission reductions than those required by standards of performance for new sources. Section 173 of the Act requires, among other things, that a new or modified source constructed in an area which exceeds the NAAQS must reduce emissions to the level which reflects the "lowest achievable emission rate" for such category of source as defined in section 171(3), unless the owner or operator demonstrates that the source cannot achieve such an emission rate. In no event can the emission rate exceed any applicable standard of performance.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area which falls under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology. The term "best available control technology" (BACT) means "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act."

Standards of performance should not be viewed as the ultimate in achievable emission control and should not preclude the imposition of a more stringent emission standard, where appropriate. For example, while cost of achievement may be an important factor in determining standards of performance applicable to all areas of the country (clean as well as dirty), costs must be accorded far less weight in determining the "lowest achievable emission rate" for new or modified sources locating in areas violating statutorily-mandated health and welfare standards. Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. This in no way should preclude its use in situations where cost is a lesser consideration, such as determination of the "lowest achievable emission rate."

In addition, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Thus, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

Environmental and Economic Impacts

The impact of the NO_x emission standards will be most significant in North Dakota and Texas where most new lignite-fired boilers will be located. Although ambient NO_x levels in these areas are now low, emission regulations are important because: (1) The standards will maintain low ambient NO_x concentrations in areas where population and industrial growth is expected in the future; (2) the standards will reduce the potential for development of rural smog which can form in regions having initially low ambient NO_x concentrations; and (3) the standards will reduce long distance transport of NO_x to areas having air pollution problems. In addition, since nationwide levels of NO_x are expected to rise in the future despite NO_x control regulations, the NO_x emission standards for lignite-fired boilers will help to alleviate this problem.

The standards will cause total NO_x emissions from all new lignite-fired steam generators to be reduced by about 25 percent. By comparison, NO_x emissions would have been reduced by about 29 percent if the use of cyclones had been restricted by the standard originally proposed. Thus, the continued use of cyclone-fired boilers will have only a minor adverse impact on air quality.

The NO_x emission standards will have no impact on water pollution, solid waste disposal, sulfur dioxide and particulate emissions, or energy consumption at new lignite-fired steam generators. In addition, the standards will not prohibit the use of any lignite reserves or adversely affect any other natural resources. Additional information about the environmental impact of the standards appears in Volumes 1 and 2 of the SSEIS.

The NO_x emission standards will cause capital costs for new lignite-fired plants to increase by, at most, only 0.5 percent and operating costs will rise even less. Therefore, capital and operating expenses will rise only nominally. Since the price consumers pay for electric power is generally proportional to the electric utility's operating costs, consumer power price increases will be negligible. The boiler manufacturers will experience no significant market disadvantages because the standards effectively permit the sale of all boiler designs and provide no sales advantages for any manufacturer. The small increases in capital costs resulting from the standards will not affect the boiler industry's overall sales. More information about the economic impact of the standards can be found in Volumes 1 and 2 of the SSEIS.

Public Comments

Seventeen comment letters were received during the public comment period. Many of the comments were critical of the information EPA used to support restriction of the cyclone-fired boiler. In particular, these arguments were made: (1) None of the pulverized-fired boilers which EPA tested operate reliably when burning lignite with a sodium content above about 5 percent; (2) the front-wall-fired plant cited by EPA has never burned lignite with an 8 percent sodium content for an extended period of time, as EPA has reported. Also, the plant's capacity factor has averaged about 72 percent, not 86 percent as stated by EPA; (3) although it is true that a North Dakota electric utility has recently agreed to purchase two tangentially-fired boilers, these units are guaranteed to burn lignite containing no more than 4.8 percent sodium. Also, the decision to purchase these boilers may have been influenced by the utility's concern that EPA might prohibit the use of cyclones; (4) recent experiments by the Energy Research and Development Administration have demonstrated that cyclone-fired boilers have significantly lower ash deposition rates than pulverized-fired boilers. This confirms arguments that cyclones have much lower fouling and slagging potentials when burning high sodium content lignite.

EPA agrees that there has not been enough successful operating experience with pulverized-fired boilers

which burn high sodium content lignite to justify eliminating cyclones from the market. Consequently, the Agency has decided to establish a separate NO_x emission standard for cyclones burning Dakota lignite which permits their use.

Another issue raised during the comment period concerned the potentially high NO_x emissions which could occur when Texas lignite with a high nitrogen content is burned. It was argued that these emissions could exceed the standard even if the best system of emission reduction were employed. In support of this contention, a commenter submitted data which indicate that the fuel-nitrogen content of Texas lignites ranges well above expected values. EPA has determined, however, that these data were accumulated around the turn of the century and are inconsistent with present-day values. Information from the Bureau of Economic Geology at the University of Texas and the Texas Railroad Commission indicates that Texas lignite nitrogen contents are typically low and should not cause NO_x emissions from a well controlled plant to exceed the standard.

These and all other comments are discussed in detail in Volume 2, Chapter 2 of the SSEIS.

The effective date of this regulation is (date of publication), because section 111(b)(1)(B) of the Clean Air Act provides that standards of performance or revisions thereof become effective upon promulgation.

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Analysis under Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: March 2, 1978.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended by revising Subparts A and D as follows:

Subpart A—General Provisions

1. Section 60.2 is amended by substituting the International System of Units (SI) in paragraph (1) as follows:

§ 60.2 Definitions.

* * * * *

(1) "Standard conditions" means a temperature of 293 K (68° F) and a pressure of 101.3 kilopascals (29.92 in Hg).

* * * * *

Subpart D—Standards of Performance for Fossil Fuel-Fired Steam Generators

2. Section 60.40 is amended by revising paragraph (c) and by adding paragraph (d) as follows:

§ 60.40 Applicability and designation of affected facility.

* * * * *

(c) Except as provided in paragraph (d) of this section, any facility under paragraph (a) of this section that commenced construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(d) The requirements of §§ 60.44(a)(4), (a)(5), (b), and (d), and 60.45(f)(4)(vi) are applicable to lignite-fired steam generating units that commenced construction or modification after December 22, 1976.

3. Section 60.41 is amended by adding paragraph (f) as follows:

§ 60.41 Definitions.

* * * * *

(f) "Coal" means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society for Testing Material. Designation D 388-66.

4. Section 60.44 is amended by adding paragraphs (a)(4) and (a)(5), by revising paragraph (b), and by adding paragraphs (c) and (d) as follows:

§ 60.44 Standard for nitrogen oxides.

(a) * * *

(4) 260 nanograms per joule heat input (0.60 lb per million Btu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).

(5) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.

(b) Except as provided under paragraphs (c) and (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NO_x} = \frac{w(260)+x(86)+y(130)+z(300)}{w+x+y+z}$$

where:

PS_{NO_x} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;

w = is the percentage of total heat input derived from lignite;

x = is the percentage of total heat input derived from gaseous fossil fuel;

y = is the percentage of total heat input derived from liquid fossil fuel; and

z = is the percentage of total heat input derived from solid fossil fuel (except lignite).

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for nitrogen oxides does not apply.

(d) Cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota, South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel combusted in combination with that lignite.

(Sections 111 and 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411, and 7601).)

5. Section 60.45 is amended by adding paragraph (f)(4)(vi) as follows:

§ 60.45 Emission and fuel monitoring.

* * * * *

(f) * * *

(4) * * *

(vi) For lignite coal as classified according to A.S.T.M. D 388-66, $F = 2.659 \times 10^{-7}$ dscm/J (9900 dscf/million Btu) and $F_c = 0.516 \times 10^{-7}$ scm CO_2/J (1920 scf CO_2/million Btu).

(Sections 111, 114, and 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411, 7414, and 7601).)

[FR Doc. 78-5975 Filed 3-6-78; 8:45 am]

FEDERAL REGISTER, VOL. 43, NO. 45

TUESDAY, MARCH 7, 1978

85

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 835-2]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Lime Manufacturing Plants

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This rule establishes standards of performance which limit emissions of particulate matter from new, modified, and reconstructed lime manufacturing plants. The standards implement the Clean Air Act and are based on the Administrator's determination that lime manufacturing plant emissions contribute significantly to air pollution. The intended effect of setting these standards is to require new, modified, and reconstructed lime manufacturing plants to use the best demonstrated system of continuous emission reduction.

EFFECTIVE DATE: March 7, 1978.

ADDRESSES: A support document entitled, "Standard Support and Environmental Impact Statement, Volume II: Promulgated Standards of Performance for Lime Manufacturing Plants" (EPA-450/2-77-007b), October 1977, has been prepared and is available. This document includes summary economic and environmental impact statements as well as EPA's responses to the comments on the proposed standards. Also available is the supporting volume for the proposed standards entitled, "Standard Support and Environmental Impact Statement, Volume I: Proposed Standards of Performance for Lime Manufacturing Plants" (EPA-450/2-77-007a), April 1977. Copies of these documents can be ordered by addressing a request to the EPA Library (MD-35), Research Triangle Park, N.C. 27711. The title and number for each or both of the documents should be specified when ordering. These documents as well as copies of the comment letters responding to the proposed rulemaking published in the FEDERAL REGISTER on May 3, 1977 (42 FR 22506) are available for public inspection and copying at the U.S. Environmental Protection Agency, Public Information Reference Unit (EPA Library), Room 2922, 401 M Street SW., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: There are two minor changes in the standards from those proposed on May 3, 1977. The first of these is the specific exclusion of lime production units at kraft pulp mills [§60.340(b)]. Emission standards for kraft pulp mills were proposed in the FEDERAL REGISTER on September 24, 1976, which cover emissions from the lime production units at these mills.

The second change is the addition of §60.344(c) (Test methods and procedures). The addition recommends a testing technique which would more accurately test exhaust gases from hydrators in those cases where high moisture content is a problem.

During the 60-day comment period following publication of the proposed emission standards in the FEDERAL REGISTER on May 3, 1977, 23 comment letters were received, 10 from industry, 7 from State or local pollution control agencies, and 6 from other government agencies. In addition, on June 16, 1977, a public meeting was held at the EPA facility at Research Triangle Park, N.C., that provided an opportunity for oral presentations and comments on the standards. None of the comments warranted a change of the emission standards nor did any comments justify any significant changes in the standards support document.

Major comments focused on three areas: (1) criticism of the testing procedures and the supporting emission data, (2) the opacity standard, and (3) the requirement for continuous monitoring. These and other comments are summarized and addressed in Volume II of the standards support document.

The most significant of the three areas of comments was the questioning of the testing procedures and the data base. More specifically, it was asserted that when data were gathered upon which to base the standard, standard testing procedures were not followed in every case, which consequently biased the data. A careful review of the procedures and the resulting data revealed that, although there were minor miscalculations, the errors did not affect the emission standards that were set.

The opacity standard (10 percent), was questioned because it was thought to be too stringent and in a range where observer error would result in unfair violation decisions. A review of the opacity data indicated that of the 1,056 six-minute averages of opacity, less than one percent exceeded the visible emission level of 10 percent, thus EPA considers the 10 percent opacity standard reasonable. As for observer error, as indicated in the introduction to Reference Method 9 (Part 60, Appendix A), the accuracy of the method and any potential error must be taken into account when determining possible violations of the standards.

Some commenters questioned the requirement for continuous monitoring of multiple stack baghouses, believing it to be unnecessary and excessively expensive to place a monitor on each stack. In establishing the continuous monitoring requirement, it was not the intention of EPA that emission monitors be installed at each stack at a multiple stack baghouse. The proposed regulation has been revised to reflect this intent. It is believed that in most cases one monitor, or two in certain situations, can be installed to simultaneously monitor emissions from several stacks. With such a monitoring system, the plant must demonstrate that representative emissions are monitored on a continuous basis.

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements). State implementation plans (SIPs) approved or promulgated under section 110 of the Act, on the other hand, must provide for the attainment and maintenance of national ambient air quality standards (NAAQS) designed to protect public health and welfare. For that purpose, SIPs must in some cases require greater emission reductions than those required by standards of performance for new sources. Section 173 of the Act requires, among other things, that a new or modified source constructed in an area which exceeds the NAAQS must reduce emissions to the level which reflects the "lowest achievable emission rate" for such category of source. In no event can the emission rate exceed any applicable standard of performance.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area which falls under the prevention of significant deterioration of air quality provisions of the Act (part C). These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology for all pollutants regulated under the Act. The term "best available control technology" (BACT), as defined in section 169(3), means "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results

from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act."

Standards of performance should not be viewed as the ultimate in achievable emission control and should not preclude the imposition of a more stringent emission standard, where appropriate. For example while cost of achievement may be an important factor in determining standards of performance applicable to all areas of the country (clean as well as dirty), statutorily, costs do not play such a role in determining the "lowest achievable emission rate" for new or modified sources locating in areas violating statutorily-mandated health and welfare standards. Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. This in no way should preclude its use in situations where cost is a lesser consideration, such as determination of the "lowest achievable emission rate."

In addition, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Thus, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

MISCELLANEOUS: The effective date of this regulation is March 7, 1978. Section 111(b)(1)(B) of the Clean Air Act provides that standards of performance or revisions of them become effective upon promulgation and apply to affected facilities, construction or modification of which was commenced after the date of proposal (May 3, 1977).

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring an Economic Impact Analysis under Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: March 1, 1978.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I of Title 40 of the Code of Regulations is amended as follows:

1. By adding subpart HH as follows:

Subpart HH—Standards of Performance for Lime Manufacturing Plants

Sec.

60.340 Applicability and designation of affected facility.
60.341 Definitions.
60.342 Standard for particulate matter.
60.343 Monitoring of emissions and operations.
60.344 Test methods and procedures.

AUTHORITY: Sec. 111 and 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411, 7601), and additional authority as noted below.

§ 60.340 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities used in the manufacture of lime: rotary lime kilns and lime hydrators.

(b) The provisions of this subpart are not applicable to facilities used in the manufacture of lime at kraft pulp mills.

(c) Any facility under paragraph (a) of this section that commences construction or modification after May 3, 1977, is subject to the requirements of this part.

§ 60.341 Definitions.

As used in this subpart, all terms not defined herein shall have the same meaning given them in the Act and in subpart A of this part.

(a) "Lime manufacturing plant" includes any plant which produces a lime product from limestone by calcination. Hydration of the lime product is also considered to be part of the source.

(b) "Lime product" means the product of the calcination process including, but not limited to, calcitic lime, dolomitic lime, and dead-burned dolomite.

(c) "Rotary lime kiln" means a unit with an inclined rotating drum which is used to produce a lime product from limestone by calcination.

(d) "Lime hydrator" means a unit used to produce hydrated lime product.

§ 60.342 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any rotary lime kiln any gases which:

(i) Contain particulate matter in excess of 0.15 kilogram per megagram of limestone feed (0.30 lb/ton).

(ii) Exhibit 10 percent opacity or greater.

(2) From any lime hydrator any gases which contain particulate matter in excess of 0.075 kilogram per megagram of lime feed (0.15 lb/ton).

§ 60.343 Monitoring of emissions and operations.

(a) The owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate a continuous monitoring system, except as provided in paragraph (b) of this section, to monitor and record the opacity of a representative portion of the gases discharged into the atmosphere from any rotary lime kiln. The span of this system shall be set at 40 percent opacity.

(b) The owner or operator of any rotary lime kiln using a wet scrubbing emission control device subject to the provisions of this subpart shall not be required to monitor the opacity of the gases discharged as required in paragraph (a) of this section, but shall install, calibrate, maintain, and operate the following continuous monitoring devices:

(1) A monitoring device for the continuous measurement of the pressure loss of the gas stream through the scrubber. The monitoring device must be accurate within ±250 pascals (one inch of water).

(2) A monitoring device for the continuous measurement of the scrubbing liquid supply pressure to the control device. The monitoring device must be accurate within ±5 percent of design scrubbing liquid supply pressure.

(c) The owner or operator of any lime hydrator using a wet scrubbing emission control device subject to the provisions of this subpart shall install, calibrate, maintain, and operate the following continuous monitoring devices:

(1) A monitoring device for the continuous measuring of the scrubbing liquid flow rate. The monitoring device must be accurate within ±5 percent of design scrubbing liquid flow rate.

(2) A monitoring device for the continuous measurement of the electric current, in amperes, used by the scrubber. The monitoring device must be accurate within ±10 percent over its normal operating range.

(d) For the purpose of conducting a performance test under § 60.8, the owner or operator of any lime manufacturing plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a device for measuring the mass rate of limestone feed to any affected rotary lime

kiln and the mass rate of lime feed to any affected lime hydrator. The measuring device used must be accurate to within ±5 percent of the mass rate over its operating range.

(e) For the purpose of reports required under §60.7(c), periods of excess emissions that shall be reported are defined as all six-minute periods during which the average opacity of the plume from any lime kiln subject to paragraph (a) of this subpart is 10 percent or greater.

(Sec. 114 of the Clean Air Act, as amended (42 U.S.C. 7414).)

§60.344 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided under §60.8(b), shall be used to determine compliance with §60.322(a) as follows:

(1) Method 5 for the measurement of particulate matter,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate,

(4) Method 3 for gas analysis,

(5) Method 4 for stack gas moisture, and

(6) Method 9 for visible emissions.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the sampling rate shall be at least 0.85 std m³/h, dry basis (0.53 dscf/min), except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) Because of the high moisture content (40 to 85 percent by volume) of the exhaust gases from hydrators, the Method 5 sample train may be modified to include a calibrated orifice immediately following the sample nozzle when testing lime hydrators. In this configuration, the sampling rate necessary for maintaining isokinetic conditions can be directly related to exhaust gas velocity without a correction for moisture content. Extra care should be exercised when cleaning the sample train with the orifice in this position following the test runs.

(Sec. 114 of the Clean Air Act, as amended (42 U.S.C. 7414).)

[FR Doc. 78-5974 Filed 3-6-78; 8:45 am]

FEDERAL REGISTER, VOL. 43, NO. 45

TUESDAY, MARCH 7, 1978

86

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 836-1]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Petroleum Refinery Claus Sulfur Recovery Plants

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This rule establishes standards of performance which will limit emissions of sulfur dioxide (SO_2) and reduced sulfur compounds from new, modified, and reconstructed petroleum refinery Claus sulfur recovery plants. The standards implement the Clean Air Act and are based on the Administrator's determination that emissions from petroleum refinery Claus sulfur recovery plants contribute significantly to air pollution. The intended effect of the standards is to require new, modified, and reconstructed petroleum refinery Claus sulfur recovery plants to use the best technological system of continuous emission reduction.

EFFECTIVE DATE: March 15, 1978.

ADDRESSES: Copies of the standard support documents are available on request from the U.S. EPA Library (MD-35), Research Triangle Park, N.C. 27711. The requestor should specify "Standards Support and Environmental Impact Statement, Volume I. Proposed Standards of Performance for Petroleum Refinery Sulfur Recovery Plants" (EPA-450/2-76-016a) and/or "Standards Support and Environmental Impact Statement, Volume II: Promulgated Standards of Performance for Petroleum Refinery Sulfur Recovery Plants" (EPA-450/2-76-016b). Comment letters responding to the proposed rules published in the FEDERAL REGISTER on October 4, 1976 (41 FR 43866), are available for public inspection and copying at the U.S. Environmental Protection Agency, Public Information Reference Unit (EPA Library), Room 2922, 401 M Street SW., Washington, D.C.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone number 919-541-5271.

SUPPLEMENTARY INFORMATION:

SUMMARY

On October 4, 1976 (41 FR 43866), EPA proposed standards of performance for new petroleum refinery Claus sulfur recovery plants under section 111 of the Clean Air Act, as amended. The promulgated standards are essentially the same as those proposed, although an exemption for small petroleum refineries has been included in the promulgated standards. The standards are based on the use of tail gas scrubbing systems which have been determined to be the best technological system of continuous emission reduction, taking into consideration the cost of achieving such emission reduction, any nonair quality, health, and environmental impact and energy requirements. Compliance with these standards will increase the overall sulfur recovery efficiency of a typical refinery Claus sulfur recovery plant to about 99.9 percent, compared to a recovery efficiency of about 94 percent for an uncontrolled refinery Claus sulfur recovery plant, or a recovery efficiency of about 99 percent for a Claus sulfur recovery plant complying with typical State emission control regulations for these plants.

The promulgated standards will apply to: (1) any Claus sulfur recovery plant with a sulfur production capacity of more than 20 long tons per day (LTD) which is associated with a small petroleum refinery (i.e., a petroleum refinery having a crude oil processing capacity of 50,000 barrels per stream day (BSD) or less which is owned or controled by a refiner whose total combined crude oil processing capacity is 137,500 BSD or less) and (2) any size Claus sulfur recovery plant associated with a large petroleum refinery. Specifically, the standards limit the concentration of sulfur dioxide (SO_2) in the gases discharged into the atmosphere to 0.025 percent by volume at zero percent oxygen on a dry basis. Where the emission control system installed to comply with these standards discharges residual emissions of hydrogen sulfide (H_2S), carbonyl sulfide (COS), and carbon disulfide (CS_2), the standards limit the concentration of H_2S and the total concentration of H_2S, COS and CS_2 (calculated as SO_2) in the gases discharged into the atmosphere to 0.0010 percent and 0.030 percent by volume at zero percent oxygen on a dry basis, respectively.

Compliance with these standards will reduce nationwide sulfur dioxide emissions by some 55,000 tons per year by 1980. This reduction will be achieved without any significant adverse impact on other aspects of environmental quality, such as solid waste disposal, water pollution, or noise. This reduction in emissions will also be accompanied by a reduction in the

growth of nationl energy consumption equivalent to about 90,000 barrels of fuel oil per year by 1980.

The economic impact of the promulgated standards is reasonable. They will result in an increase in the annual operating costs of the petroleum refining industry by some $16 million per year in 1980. An individual refiner who installs alternative II controls will need to increase his prices from 0.1 to 1 percent to maintain his profitability.

It should be noted that standards of performance for new sources established under section 111 of the Act reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements). State implementation plans (SIPs) approved or promulgated under section 110 of the Act, on the other hand, must provide for the attainment and maintenance of national ambient air quality standards (NAAQS) designed to protect public health and welfare. For that purpose, SIPs must in some cases require greater emission reduction than those required by standards of performance for new sources. Section 173(2) of the Act requires, among other things, that a new or modified source constructed in an area which exceeds the NAAQS must reduce emissions to the level which reflects the "lowest achievable emission rate" for such category of source, unless the owner or operator demonstrates that the source cannot achieve such an emission rate. In no event can the emission rate exceed any applicable standard of performance.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area which falls under the prevention of significant deterioration of air quality provisions of the Act (part C). These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to the best available control technology. The term "best available control technology" (BACT) means "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act."

Standards of performance should not be viewed as the ultimate in achievable emission control and should not preclude the imposition of a more stringent emission standard, where appropriate. For example, while cost of achievement may be an important factor in determining standards of performance applicable to all areas of the country (clean as well as dirty), costs must be accorded far less weight in determining the "lowest achievable emission rate" for new or modified sources locating in areas violating statutorily-mandated health and welfare standards. Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. This in no way should preclude its use in situations where cost is a lesser consideration, such as determination of the "lowest achievable emission rate."

In addition, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

Public Participation

Prior to proposal of the standards, interested parties were advised by public notice in the Federal Register of a meeting of the National Air Pollution Control Techniques Advisory Committee to discuss the standards recommended for proposal. This meeting was open to the public and each person attending was given ample opportunity to comment on the standards recommended for proposal. The standards were proposed on October 4, 1976, and copies of the proposed standards and the Standards Support and Environmental Impact Statement (SSEIS) were distributed to members of the petroleum refining industry and several environmental groups at this time. The public comment period extended from October 4, 1976, to December 3, 1976.

Twenty-two comment letters were received on the proposed standards of performance. These comments have been carefully considered and, where determined to be appropriate by the Administrator, changes have been made in the standards which were proposed.

Major Comments

Comments on the proposed standards were received from several oil industry representatives, State and local air pollution control agencies, a vendor of emission source testing equipment, and several Federal agencies. These comments covered four major areas: the costs of implementing the standards, the ability of emission control technology to meet the standards, the environmental impacts of the standards, and the energy impacts of the standards.

COSTS

The major comments concerning costs were that the costs of the emission control systems required to meet the standards were underestimated, that these costs were excessive; and that small sulfur recovery plants, or small petroleum refineries should be exempt from the standard.

The basic cost data used to develop the cost estimates were obtained from pretroleum refinery sources. No specific data or information was provided in the public comments, however, which would indicate that these costs are significantly in error.

In the preamble to the proposed standards, comments were specifically invited concerning the impact of the standards on the small refiner. After considering these comments, EPA has concluded that some relief from the standards is appropriate. The major factor involved in this decision was a consideration of the cost effectiveness of the standards on large and small refiners. The incremental cost per incremental unit of sulfur emissions that must be controlled to meet the standards is substantially greater for the small refiner than for the large refiner. Furthermore, the impact of these costs on the small refiner is more severe than the impact on the large refiner, because the small refiner cannot readily pass on the cost of emission control equipment. Consequently, as discussed in volume II of the Standards Support and Environmental Impact Statement (SSEIS), the promulgated standards include a lower size cutoff for small petroleum refineries and Claus sulfur recovery plants. Claus sulfur recovery plants with a sulfur production capacity of 20 long tons per day or less associated with a petroleum refinery with a crude oil processing capacity of 50,000 BSD or less, which is owned or controlled by a refiner whose total combined crude oil processing capacity is 137,500 BSD or less, are exempt from the standards. This definition of a small petroleum refinery is consistent with that included in section 211 of the Clean Air Act, as amended.

EMISSION CONTROL TECHNOLOGY

A major concern of many commenters was the limited amount of source test data used in support of the numerical emission limits included in the standards and the fact that some of these data were collected at refineries where the emission control system was operating below design capacity. Also, some commenters questioned the ability of the alternative II emission control systems to continuously operate at a 99.9 percent control efficiency because of the adverse impact of Claus sulfur recovery plant fluctuations and CO_2-rich waste gas streams.

In arriving at the numerical emissions limits included in the standards, source test data collected by a local agency at times when the emission control systems were operating at normal capacities, information from vendors of emission control equipment, published literature on emission control technology, and contractor reports on the performance of emission control technology were considered, in addition to the data collected during EPA's source tests. Based on the information and data from these sources and the lack of any new information and data submitted by the commenters, no change in the emission limits of the standards is warranted. Furthermore, the numerical emission limits in the standards contain an adequate safety margin to allow for increased emissions due to Clause sulfur recovery plant fluctuations.

With repect to the potential adverse impact of high CO_2 gas streams, this is not likely to impair the overall emission control system efficiency since high CO_2 gas streams are seldom found in the gases treated in refinery Claus sulfur recovery plants.

ENVIRONMENTAL IMPACT

Several commenters felt that the assessment of the environmental impact of the standards was, in some cases, biased and not always clear. One of these commenters suggested that a thorough environmental impact statement should be prepared to clarify the impacts of the standards.

Litigation involving standards of performance has established that preparation of a formal environmental impact statement under the National Environmental Policy Act is not necessary for actions under section 111 of the Clean Air Act. While a formal environmental impact statement is not prepared, the beneficial as well as the adverse impacts of standards of performance are considered. The promulgated standards will significantly reduce emissions of sulfur from petroleum refineries without resulting in any significant adverse environmental, energy, or economic impacts.

Other commenters felt that standards based on 99 percent control (alternative I) would be essentially as environmentally beneficial as standards based on 99.9 percent control and would be less costly to the public. This argument was based on the premise that most State regulations do not require control of Claus sulfur plant emissions at the 99 percent level as claimed in volume I of the SSEIS. Hence, standards based on alternative I would significantly reduce national sulfur emissions from refinery Claus sulfur recovery plants.

A review of State regulations for controlling emissions from refinery sulfur recovery plants has shown that the majority of the States with the largest petroleum refining capacities require 99 percent control of emissions from new and existing sulfur recovery plants. Since refinery sulfur recovery plant growth will likely occur in these States, the conclusion that standards based on 99 percent control would have little or no beneficial impact is essentially correct.

ENERGY IMPACT

Several commenters questioned the conclusion that compliance with standards based on alternative II could lead to an energy savings, compared to standards based on alternative I. A review of the information and data available confirms this conclusion. In any case, the important consideration is whether the energy impact of the standards is reasonable. No information was submitted which would indicate that the energy impact of the standards is unreasonable.

OTHER CONSIDERATIONS

At proposal comments were requested relative to EPA's decision to regulate reduced sulfur compound emissions, which are designated pollutants, without implementing section 111(d) of the Clean Air Act at this time. The one commenter who responded to this issue was in agreement with this decision.

As discussed in both the preamble to the proposed standards and volumes I and II of the SSEIS, petroleum refinery Claus sulfur recovery plants are sources of SO_2 emissions, not reduced sulfur compound emissions. One of the emission control technologies for reducing SO_2 emissions, however, first converts these emissions to reduced sulfur compounds and then controls these compounds. Consequently, this technology may discharge residual emissions of reduced sulfur compounds to the atmosphere.

Currently, there are about 30 refinery Claus sulfur recovery plants in the United States which have installed reduction emission control systems to reduce SO_2 emissions. A review of these plants indicates that these emission control systems are well designed and well maintained and operated. Emissions of reduced sulfur compounds are less than 0.050 percent (i.e., 500 ppm), which is only slightly higher than the numerical emission limit included in the promulgated standard. Thus, there is little to gain at this time by requiring States to develop regulations limiting emissions from these sources. Consequently, section 111(d) will not be implemented until resources permit, taking into consideration other requirements of the Clean Air Act, as amended, which EPA must implement.

Several commenters were concerned that Reference Method 15 might not be practical for use in a refinery environment. The basis for most of these objections was that the commenters thought this method was being proposed as a continuous monitoring method. However, Reference Method 15 was not proposed for use as a continuous monitoring method. Performance specifications for continuous monitors for reduced sulfur compounds have not been developed and therefore such monitors are not required to be installed until performance specifications for these monitors are proposed and promulgated under Appendix B of 40 CFR Part 60.

Reference Method 15 has been revised to allow greater flexibility in operating details and equipment choice. The user is now permitted to design his own sampling and analysis system as long as he preserves the operating principle of gas chromatography with flame photometric detection and meets the design and performance criteria.

MISCELLANEOUS

The effective date of this regulation is March 15, 1978. Section 111(b)(1)(B) of the Clean Air Act provides that standards of performance or revisions of them become effective upon promulgation and apply to affected facilities, construction or modification of which was commenced after the date of proposal (October 4, 1976).

ECONOMIC IMPACT ASSESSMENT: An economic assessment has been prepared as required under section 317 of the Act. This also satisfies the requirements of Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: March 1, 1978.

DOUGLAS M. COSTLE,
Administrator.

1. Section 60.100 is amended as follows:

§ 60.100 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants of 20 long

tons per day (LTD) or less associated with a small petroleum refinery. The Claus sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(b) Any fluid catalytic cracking unit catalyst regenerator of fuel gas combustion device under paragraph (a) of this section which commences construction or modification after June 11, 1973, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction or modification after October 4, 1976, is subject to the requirements of this part.

(Secs. 111 and 301(a), Clean Air Act, as amended (42 U.S.C. 7411, 7601 (a)), and additional authority as noted below.)

2. Section 60.101 is amended as follows:

§ 60.101 Definitions.

* * * * *

(i) "Claus sulfur recovery plant" means a process unit which recovers sulfur from hydrogen sulfide by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

(j) "Oxidation control system" means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide.

(k) "Reduction control system" means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to hydrogen sulfide.

(l) "Reduced sulfur compounds" mean hydrogen sulfide (H_2S), carbonyl sulfide (COS) and carbon disulfide (CS_2).

(m) "Small petroleum refinery" means a petroleum refinery which has a crude oil processing capacity of 50,000 barrels per stream day or less, and which is owned or controlled by a refinery with a total combined crude oil processing capacity of 137,500 barrels per stream day or less.

3. Section 60.102 is amended by revising paragraph (a) introductory text and paragraph (b) as follows:

§ 60.102 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator:

(1) * * *

(2) * * *

(b) Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator or waste heat boiler in which auxiliary or supplemental liquid or sold fossil fuel is burned, particulate matter in excess of that permitted by paragraph (a)(1) of this section may be emitted to the atmosphere, except that the incremental rate of particulate matter emissions shall not exceed 43.0 g/MJ (0.10 lb/million Btu) of heat input attributable to such liquid or solid fossil fuel.

4. Section 60.104 is amended as follows:

§ 60.104 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall:

(1) Burn in any fuel gas combustion device any fuel gas which contains hydrogen sulfide in excess of 230 mg/dscm (0.10 gr/dscf), except that the gases resulting from the combustion of fuel gas may be treated to control sulfur dioxide emissions provided the owner or operator demonstrates to the satisfaction of the Administrator that this is as effective in preventing sulfur dioxide emissions to the atmosphere as restricting the H_2 concentration in the fuel gas to 230 mg/dscm or less. The combustion in a flare of process upset gas, or fuel gas which is released to the flare as a result of relief valve leakage, is exempt from this paragraph.

(2) Discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of:

(i) 0.025 percent by volume of sulfur dioxide at zero percent oxygen on a dry basis if emissions are controlled by an oxidation control system, or a reduction control system followed by incineration, or

(ii) 0.030 percent by volume of reduced sulfur compounds and 0.0010 percent by volume of hydrogen sulfide calculated as sulfur dioxide at zero percent oxygen on a dry basis if emissions are controlled by a reduction control system not followed by incineration.

(b) [Reserved]

5. Section 60.105 is amended as follows:

§ 60.105 Emission monitoring.

(a) * * *

(2) An instrument for continuously monitoring and recording the concentration of carbon monoxide in gases discharged into the atmosphere from fluid catalytic cracking unit catalyst regenerators. The span of this continuous monitoring system shall be 1,000 ppm.

(3) * * *

(4) An instrument for continuously monitoring and recording concentrations of hydrogen sulfide in fuel gases burned in any fuel gas combustion device, if compliance with § 60.104(a)(1) is achieved by removing H_2S from the fuel gas before it is burned; fuel gas combustion devices having a common source of fuel gas may be monitored at one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas burned. The span of this continuous monitoring system shall be 300 ppm.

(5) An instrument for continuously monitoring and recording concentrations of SO_2 in the gases discharged into the atmosphere from any Claus sulfur recovery plant if compliance with § 60.104(a)(2) is achieved through the use of an oxidation control system or a reduction control system followed by incineration. The span of this continuous monitoring system shall be sent at 500 ppm.

(6) An instrument(s) for continuously monitoring and recording the concentration of H_2S and reduced sulfur compounds in the gases discharged into the atmosphere from any Claus sulfur recovery plant if compliance with § 60.104(a)(2) is achieved through the use of a reduction control system not followed by incineration. The span(s) of this continuous monitoring system(s) shall be set at 20 ppm for monitoring and recording the concentration of H_2S and 600 ppm for monitoring and recording the concentration of reduced sulfur compounds.

* * * * *

(e) * * *

(1) * * *

(2) Carbon monoxide. All hourly periods during which the average carbon monoxide concentration in the gases discharged into the atmosphere from any fluid catalytic cracking unit catalyst regenerator subject to § 60.103 exceeds 0.050 percent by volume.

(3) Sulfur dioxide. (i) Any three-hour period during which the average concentration of H_2S in any fuel gas combusted in any fuel gas combustion device subject to § 60.104(a)(1) exceeds 230 mg/dscm (0.10 gr/dscf), if compliance is achieved by removing H_2S from the fuel gas before it is burned; or any three-hour period during which the average concentration of SO_2 in the gases discharged into the atmosphere from any fuel gas combustion device subject to § 60.104(a)(1) exceeds the level specified in § 60.104(a)(1), if compliance is achieved by removing SO_2 from the combusted fuel gases.

(ii) Any twelve-hour period during which the average concentration of SO_2 in the gases discharged into the atmosphere from any Claus sulfur recovery plant subject to § 60.104(a)(2) exceeds 250 ppm at zero percent oxygen on a dry basis if compliance with § 60.104(b) is achieved through the use of an oxidation control system

or a reduction control system followed by incineration; or any twelve-hour period during which the average concentration of H_2S, or reduced sulfur compounds in the gases discharged into the atmosphere of any Claus sulfur plant subject to § 60.104(a)(2)(b) exceeds 10 ppm or 300 ppm, respectively, at zero percent oxygen and on a dry basis if compliance is achieved through the use of a reduction control system not followed by incineration.

6. Section 60.106 is amended as follows:

§ 60.106 Test methods and procedures.

* * * * *

(c) For the purpose of determining compliance with § 60.104(a)(1), Method 11 shall be used to determine the concentration of H_2S and Method 6 shall be used to determine the concentration of SO_2.

(1) If Method 11 is used, the gases sampled shall be introduced into the sampling train at approximately atmospheric pressure. Where refinery fuel gas lines are operating at pressures substantially above atmosphere, this may be accomplished with a flow control valve. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line. The minimum sampling time shall be 10 minutes and the minimum sampling volume 0.01 dscm (0.35 dscf) for each sample. The arithmetic average of two samples of equal sampling time shall constitute one run. Samples shall be taken at approximately 1-hour intervals. For most fuel gases, sample times exceeding 20 minutes may result in depletion of the collecting solution, although fuel gases containing low concentrations of hydrogen sulfide may necessitate sampling for longer periods of time.

(2) If Method 6 is used, Method 1 shall be used for velocity traverses and Method 2 for determining velocity and volumetric flow rate. The sampling site for determining SO_2 concentration by Method 6 shall be the same as for determining volumetric flow rate by Method 2. The sampling point in the duct for determining SO_2 concentration by Method 6 shall be at the centroid of the cross section if the cross sectional area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 inches) if the cross sectional area is 5 m^2 or more and the centroid is more than one meter from the wall. The sample shall be extracted at a rate proportional to the gas velocity at the sampling point. The minimum sampling time shall be 10 minutes and the minimum sampling volume 0.01 dscm (0.35 dscf) for each sample. The arithmetic average of two samples of equal sampling time shall constitute one run. Samples shall be taken at approximately 1-hour intervals.

(d) For the purpose of determining compliance with § 60.104(a)(2), Method 6 shall be used to determine the concentration of SO_2 and Method 15 shall be used to determine the concentration of H_2S and reduced sulfur compounds.

(1) If Method 6 is used, the procedure outlined in paragraph (c)(2) of this section shall be followed except that each run shall span a minimum of four consecutive hours of continuous sampling. A number of separate samples may be taken for each run, provided the total sampling time of these samples adds up to a minimum of four consecutive hours. Where more than one sample is used, the average SO_2 concentration for the run shall be calculated as the time weighted average of the SO_2 concentration for each sample according to the formula:

$$C_R = \sum_{i=1}^{N} C_{S_i} \frac{t_{S_i}}{T}$$

Where:

C_R = SO_2 concentration for the run.
N = Number of samples.
C_{S_i} = SO_2 concentration for sample i.
t_{S_i} = Continuous sampling time of sample i.
T = Total continuous sampling time of all N samples.

(2) If Method 15 is used, each run shall consist of 16 samples taken over a minimum of three hours. The sampling point shall be at the centroid of the cross section of the duct if the cross sectional area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 inches) if the cross sectional area is 5 m^2 or more and the centroid is more than 1 meter from the wall. To insure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3 liters/minute (0.1 ft^3/min). The SO_2 equivalent for each run shall be calculated as the arithmetic average of the SO_2 equivalent of each sample during the run. Reference Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 15. The sample shall be extracted at a rate proportional to the gas velocity at the sampling point. Each run shall span a minimum of four consecutive hours of continuous sampling. A number of separate samples may be taken for each run provided the total sampling time of these samples adds up to a minimum of four consecutive hours. Where more than one sample is used, the average moisture content for the run shall be calculated as the time weighted average of the moisture content of each sample according to the formula:

$$B_{wo} = \sum_{i=1}^{N} B_{wi} \left[\frac{t_{si}}{T}\right]$$

B_{wo} = Proportion by volume of water vapor in the gas stream for the run.
N = Number of samples.
B_{wi} = Proportion by volume of water vapor in the gas stream for the sample i.
t_{si} = Continuous sampling time for sample i.
T = Total continuous sampling time of all N samples.

(Sec. 114 of the Clean Air Act, as amended [42 U.S.C. 7414]).

* * * * *

APPENDIX A—REFERENCE METHODS

7. Appendix A is amended by adding a new reference method as follows:

METHOD 15. DETERMINATION OF HYDROGEN SULFIDE, CARBONYL SULFIDE, AND CARBON DISULFIDE EMISSIONS FROM STATIONARY SOURCES

INTRODUCTION

The method described below uses the principle of gas chromatographic separation and flame photometric detection (FPD). Since there are many systems or sets of operating conditions that represent usable methods of determining sulfur emissions, all systems which employ this principle, but differ only in details of equipment and operation, may be used as alternative methods, provided that the criteria set below are met.

1. Principle and applicability

1.1 Principle. A gas sample is extracted from the emission source and diluted with clean dry air. An aliquot of the diluted sample is then analyzed for hydrogen sulfide (H_2S), carbonyl sulfide (COS), and carbon disulfide (CS_2) by gas chromatographic (GC) separation and flame photometric detection (FPD).

1.2 Applicability. This method is applicable for determination of the above sulfur compounds from tail gas control units of sulfur recovery plants.

2. Range and sensitivity

2.1 Range. Coupled with a gas chromtographic system utilizing a 1-milliliter sample size, the maximum limit of the FPD for each sulfur compound is approximately 10 ppm. It may be necessary to dilute gas samples from sulfur recovery plants hundredfold (99:1) resulting in an upper limit of about 1000 ppm for each compound.

2.2 The minimum detectable concentration of the FPD is also dependent on sample size and would be about 0.5 ppm for a 1 ml sample.

3. Interferences

3.1 Moisture Condensation. Moisture condensation in the sample delivery system, the analytical column, or the FPD burner block can cause losses or interferences. This potential is eliminated by heating the sample line, and by conditioning the sample with dry dilution air to lower its dew point below the operating temperature of the GC/FPD analytical system prior to analysis.

3.2 Carbon Monoxide and Carbon Dioxide. CO and CO_2 have substantial desensitizing

effects on the flame photometric detector even after 9.1 dilution (Acceptable systems must demonstrate that they have eliminated this interference by some procedure such as eluding CO and CO_2 before any of the sulfur compounds to be measured.) Compliance with this requirement can be demonstrated by submitting chromatograms of calibration gases with and without CO_2 in the diluent gas. The CO_2 level should be approximately 10 percent for the case with CO_2 present. The two chromatographs should show agreement within the precision limits of section 4.1.

3 3 Elemental Sulfur. The condensation of sulfur vapor in the sampling line can lead to eventual coating and even blockage of the sample line. This problem can be eliminated along with the moisture problem by heating the sample line.

4. Precision

4 1 Calibration Precision. A series of three consecutive injections of the same calibration gas, at any dilution, shall produce results which do not vary by more than ±13 percent from the mean of the three injections.

4.2 Calibration Drift. The calibration drift determined from the mean of three injections made at the beginning and end of any 8-hour period shall not exceed ±5 percent.

5. Apparatus

5.1.1 Probe. The probe must be made of inert material such as stainless steel or glass. It should be designed to incorporate a filter and to allow calibration gas to enter the probe at or near the sample entry point. Any portion of the probe not exposed to the stack gas must be heated to prevent moisture condensation.

5.1.2 The sample line must be made of Teflon,[1] no greater than 1.3 cm (½ in) inside diameter. All parts from the probe to the dilution system must be thermostatically heated to 120° C.

5.1.3 Sample Pump. The sample pump shall be a leakless Teflon coated diaphragm type or equivalent. If the pump is upstream of the dilution system, the pump head must be heated to 120° C.

5.2 Dilution System. The dilution system must be constructed such that all sample contacts are made of inert material (e.g. stainless steel or Teflon). It must be heated to 120° C and be capable of approximately a 9:1 dilution of the sample.

5.3 Gas Chromatograph. The gas chromatograph must have at least the following components:

5.3.1 Oven. Capable of maintaining the separation column at the proper operating temperature ±1° C.

5.3.2 Temperature Gauge. To monitor column oven, detector, and exhaust temperature ±1° C.

5.3.3 Flow System. Gas metering system to measure sample, fuel, combustion gas, and carrier gas flows.

5.3.4 Flame Photometric Detector.

5.3.4.1 Electrometer. Capable of full scale amplification of linear ranges of 10^{-9} to 10^{-4} amperes full scale.

5.3.4.2 Power Supply. Capable of delivering up to 750 volts.

5.3 4.3 Recorder. Compatible with the output voltage range of the electrometer.

[1]Mention of trade names or specific products does not constitute an endorsement by the Environmental Protection Agency.

5.4 Gas Chromatograph Columns. The column system must be demonstrated to be capable of resolving three major reduced sulfur compounds: H_2S, COS, and CS_2.

To demonstrate that adequate resolution has been achieved the tester must submit a chromatograph of a calibration gas containing all three reduced sulfur compounds in the concentration range of the applicable standard. Adequate resolution will be defined as base line separation of adjacent peaks when the amplifier attenuation is set so that the smaller peak is at least 50 percent of full scale. Base line separation is defined as a return to zero ±5 percent in the interval between peaks. Systems not meeting this criteria may be considered alternate methods subject to the approval of the Administrator.

5.5.1 Calibration System. The calibration system must contain the following components.

5.5.2 Flow System. To measure air flow over permeation tubes at ±2 percent. Each flowmeter shall be calibrated after a complete test series with a wet test meter. If the flow measuring device differs from the wet test meter by 5 percent, the completed test shall be discarded. Alternatively, the tester may elect to use the flow data that would yield the lowest flow measurement. Calibration with a wet test meter before a test is optional.

5.5.3 Constant Temperature Bath. Device capable of maintaining the permeation tubes at the calibration temperature within ±1.1° C.

5.5.4 Temperature Gauge. Thermometer or equivalent to monitor bath temperature within ±1° C.

6. Reagents

6.1 Fuel. Hydrogen (H_2) prepurified grade or better.

6.2 Combustion Gas. Oxygen (O_2) or air, research purity or better.

6.3 Carrier Gas. Prepurified grade or better.

6.4 Diluent. Air containing less than 0.5 ppm total sulfur compounds and less than 10 ppm each of moisture and total hydrocarbons.

6.5 Calibration Gases. Permeation tubes, one each of H_2S, COS, and CS_2, gravimetrically calibrated and certified at some convenient operating temperature. These tubes consist of hermetically sealed FEP Teflon tubing in which a liquified gaseous substance is enclosed. The enclosed gas permeates through the tubing wall at a constant rate. When the temperature is constant, calibration gases covering a wide range of known concentrations can be generated by varying and accurately measuring the flow rate of diluent gas passing over the tubes. These calibration gases are used to calibrate the GC/FPD system and the dilution system.

7. Pretest Procedures

The following procedures are optional but would be helpful in preventing any problem which might occur later and invalidate the entire test.

7.1 After the complete measurement system has been set up at the site and deemed to be operational, the following procedures should be completed before sampling is initiated.

7.1.1 Leak Test. Appropriate leak test procedures should be employed to verify the integrity of all components, sample lines, and connections. The following leak test procedure is suggested: For components upstream of the sample pump, attach the probe end of the sample line to a manometer or vacuum gauge, start the pump and pull greater than 50 mm (2 in) Hg vacuum, close off the pump outlet, and then stop the pump and ascertain that there is no leak for 1 minute. For components after the pump, apply a slight positive pressure and check for leaks by applying a liquid (detergent in water, for example) at each joint. Bubbling indicates the presence of a leak.

7.1.2 System Performance. Since the complete system is calibrated following each test, the precise calibration of each component is not critical. However, these components should be verified to be operating properly. This verification can be performed by observing the response of flowmeters or of the GC output to changes in flow rates or calibration gas concentrations and ascertaining the response to be within predicted limits. If any component or the complete system fails to respond in a normal and predictable manner, the source of the discrepancy should be identifed and corrected before proceeding.

8. Calibration

Prior to any sampling run, calibrate the system using the following procedures. (If more than one run is performed during any 24-hour period, a calibration need not be performed prior to the second and any subsequent runs. The calibration must, however, be verified as prescribed in section 10, after the last run made within the 24-hour period.)

8.1 General Considerations. This section outlines steps to be followed for use of the GC/FPD and the dilution system. The procedure does not include detailed instructions because the operation of these systems is complex, and it requires an understanding of the individual system being used. Each system should include a written operating manual describing in detail the operating procedures associated with each component in the measurement system. In addition, the operator shuld be familiar with the operating principles of the components; particularly the GC/FPD. The citations in the Bibliography at the end of this method are recommended for review for this purpose.

8.2 Calibration Procedure. Insert the permeation tubes into the tube chamber. Check the bath temperature to assure agreement with the calibration temperature of the tubes within ±0.1°C. Allow 24 hours for the tubes to equilibrate. Alternatively equilibration may be verified by injecting samples of calibration gas at 1-hour intervals. The permeation tubes can be assumed to have reached equilibrium when consecutive hourly samples agree within the precision limits of section 4.1.

Vary the amount of air flowing over the tubes to produce the desired concentrations for calibrating the analytical and dilution systems. The air flow across the tubes must at all times exceed the flow requirement of the analytical systems. The concentration in parts per million generated by a bube containing a specific permeant can be calculated as follows:

$$C = K \times P_r / ML$$

Equation 15-1

where:

C = Concentration of permeant produced in ppm.

P_r = Permeation rate of the tube in μg/min.

M = Molecular weight of the permeant: g/g-mole.
L = Flow rate, l/min, of air over permeant @ 20°C, 760 mm Hg.
K = Gas constant at 20°C and 760 mm Hg = 24.04 l/g mole.

8.3 Calibration of analysis system. Generate a series of three or more known concentrations spanning the linear range of the FPD (approximately 0.05 to 1.0 ppm) for each of the four major sulfur compounds. Bypassing the dilution system, inject these standards in to the GC/FPD analyzers and monitor the responses. Three injects for each concentration must yield the precision described in section 4.1. Failure to attain this precision is an indication of a problem in the calibration or analytical system. Any such problem must be identified and corrected before proceeding.

8.4 Calibration Curves. Plot the GC/FPD response in current (amperes) versus their causative concentrations in ppm on log-log coordinate graph paper for each sulfur compound. Alternatively, a least squares equation may be generated from the calibration data.

8.5 Calibration of Dilution System. Generate a know concentration of hydrogen sulfied using the permeation tube system. Adjust the flow rate of diluent air for the first dilution stage so that the desired level of dilution is approximated. Inject the diluted calibration gas into the GC/FPD system and monitor its response. Three injections for each dilution must yield the precision described in section 4.1. Failure to attain this precision in this step is an indication of a problem in the dilution system. Any such problem must be identified and corrected before proceeding. Using the calibration data for H_2S (developed under 8.3) determine the diluted calibration gas concentration in ppm. Then calculate the dilution factor as the ratio of the calibration gas concentration before dilution to the diluted calibration gas concentration determined under this paragraph. Repeat this procedure for each stage of dilution required. Alternatively, the GC/FPD system may be calibrated by generating a series of three or more concentrations of each sulfur compound and diluting these samples before injecting them into the GC/FPD system. This data will then serve as the calibration data for the unknown samples and a separate determination of the dilution factor will not be necessary. However, the precision requirements of section 4.1 are still applicable.

9. Sampling and Analysis Procedure

9.1 Sampling. Insert the sampling probe into the test port making certain that no dilution air enters the stack through the port. Begin sampling and dilute the sample approximately 9:1 using the dilution system. Note that the precise dilution factor is that which is determined in paragraph 8.5. Condition the entire system with sample for a minimum of 15 minutes prior to commencing analysis.

9.2 Analysis. Aliquots of diluted sample are injected into the GC/FPD analyzer for analysis.

9.2.1 Sample Run. A sample run is composed of 16 individual analyses (injects) performed over a period of not less than 3 hours or more than 6 hours.

9.2.2 Observation for Clogging of Probe. If reductions in sample concentrations are observed during a sample run that cannot be explained by process conditions, the sampling must be interrupted to determine if the sample probe is clogged with particulate matter. If the probe is found to be clogged, the test must be stopped and the results up to that point discarded. Testing may resume after cleaning the probe or replacing it with a clean one. After each run, the sample probe must be inspected and, if necessary, dismantled and cleaned.

10. Post-Test Procedures

10 1 Sample Line Loss. A known concentration of hydrogen sulfide at the level of the applicable standard, ±20 percent, must be introduced into the sampling system at the opening of the probe in sufficient quantities to ensure that there is an excess of sample which must be vented to the atmosphere. The sample must be transported through the entire sampling system to the measurement system in the normal manner. The resulting measured concentration should be compared to the known value to determine the sampling system loss. A sampling system loss of more than 20 percent is unacceptable. Sampling losses of 0-20 percent must be corrected by dividing the resulting sample concentration by the fraction of recovery. The known gas sample may be generated using permeation tubes. Alternatively, cylinders of hydrogen sulfide mixed in air may be used provided they are traceable to permeation tubes. The optional pretest procedures provide a good guideline for determining if there are leaks in the sampling system.

10.2 Recalibration. After each run, or after a series of runs made within a 24-hour period, perform a partial recalibration using the procedures in section 8. Only H_2S (or other permeant) need be used to recalibrate the GC/FPD analysis system (8.3) and the dilution system (8.5).

10 3 Determination of Calibration Drift. Compare the calibration curves obtained prior to the runs, to the calibration curves obtained under paragraph 10.1. The calibration drift should not exceed the limits set forth in paragraph 4.2. If the drift exceeds this limit, the intervening run or runs should be considered not valid. The tester, however, may instead have the option of choosing the calibration data set which would give the highest sample values.

11. Calculations

11.1 Determine the concentrations of each reduced sulfur compound detected directly from the calibration curves. Alternatively, the concentrations may be calculated using the equation for the least squares line.

11.2 Calculation of SO_2 Equivalent. SO_2 equivalent will be determined for each analysis made by summing the concentrations of each reduced sulfur compound resolved during the given analysis.

$$SO_2 \text{ equivalent} = \Sigma(H_2S, COS, 2\,CS_2)d$$

Equation 15-2

where:
SO_2 equivalent = The sum of the concentration of each of the measured compounds (COS, H_2S, CS_2) expressed as sulfur dioxide in ppm.
H_2S = Hydrogen sulfide, ppm.
COS = Carbonyl sulfide, ppm.
CS_2 = Carbon disulfide, ppm.
d = Dilution factor, dimensionless.

11.3 Average SO_2 equivalent will be determined as follows:

$$\text{Average } SO_2 \text{ equivalent} = \frac{\sum_{i=1}^{N} SO_2 \text{ equiv.}_i}{N\,(1 - Bwo)}$$

Equation 15-3

where:
Average SO_2 equivalent$_i$ = Average SO_2 equivalent in ppm, dry basis.
Average SO_2 equivalent$_i$ = SO_2 in ppm as determined by Equation 15-2.
N = Number of analyses performed.
Bwo = Fraction of volume of water vapor in the gas stream as determined by Method 4—Determination of Moisture in Stack Gases (36 FR 24887).

12. Example System

Described below is a system utilized by EPA in gathering NSPS data. This system does not now reflect all the latest developments in equipment and column technology, but it does represent one system that has been demonstrated to work.

12.1 Apparatus.

12.1.1 Sample System.

12.1.1.1 Probe. Stainless steel tubing, 6.35 mm (¼ in.) outside diameter, packed with glass wool.

12.1.1.2 Sample Line. 3/16 inch inside diameter Teflon tubing heated to 120° C. This temperature is controlled by a thermostatic heater.

12.1.1.3 Sample Pump. Leakless Teflon coated diaphragm type or equivalent. The pump head is heated to 120° C by enclosing it in the sample dilution box (12.2.4 below).

12.1.2 Dilution System. A schematic diagram of the dynamic dilution system is given in Figure 15-2. The dilution system is constructed such that all sample contacts are made of inert materials. The dilution system which is heated to 120° C must be capable of a minimum of 9:1 dilution of sample. Equipment used in the dilution system is listed below:

12.1.2.1 Dilution Pump. Model A-150 Kohmyhr Teflon positive displacement type, nonadjustable 150 cc/min. ±2.0 percent, or equivalent, per dilution stage. A 9:1 dilution of sample is accomplished by combining 150 cc of sample with 1350 cc of clean dry air as shown in Figure 15-2.

12.1.2.2 Valves. Three-way Teflon solenoid or manual type.

12.1.2.3 Tubing. Teflon tubing and fittings are used throughout from the sample probe to the GC/FPD to present an inert surface for sample gas.

12.1.2.4 Box. Insulated box, heated and maintained at 120° C, of sufficient dimensions to house dilution apparatus.

12.1.2.5 Flowmeters. Rotameters or equivalent to measure flow from 0 to 1500 ml/min. ±1 percent per dilution stage.

12.1.3.0 Gas Chromatograph.

12.1.3.1 Column—1.83 m (6 ft.) length of Teflon tubing, 2.16 mm (0.085 in.) inside diameter, packed with deactivated silica gel, or equivalent.

12.1.3.2 Sample Valve. Teflon six port gas sampling valve, equipped with a 1 ml sample loop, actuated by compressed air (Figure 15-1).

12.1.3.3 Oven. For containing sample valve, stripper column and separation column. The oven should be capable of maintaining an elevated temperature ranging from ambient to 100° C, constant within ±1° C.

12.1.3.4 Temperature Monitor Thermocouple pyrometer to measure column oven, detector, and exhaust temperature ±1° C.

12.1.3.5 Flow System. Gas metering system to measure sample flow, hydrogen flow, oxygen flow and nitrogen carrier gas flow.

12.1.3.6 Detector. Flame photometric detector.

12.1.3.7 Electrometer. Capable of full scale amplification of linear ranges of 10^{-9} to 10^{-4} amperes full scale.

12.1.3.8 Power Supply. Capable of delivering up to 750 volts.

12.1.3.9 Recorder. Compatible with the output voltage range of the electrometer.

12.1.4 Calibration. Permeation tube system (Figure 15-3).

12.1.4.1 Tube Chamber. Glass chamber of sufficient dimensions to house permeation tubes.

12.1.4.2 Mass Flowmeters. Two mass flowmeters in the range 0-3 l/min. and 0-10 l/min. to measure air flow over permeation tubes at ±2 percent. These flowmeters shall be cross-calibrated at the beginning of each test. Using a convenient flow rate in the measuring range of both flowmeters, set and monitor the flow rate of gas over the permeation tubes. Injection of calibration gas generated at this flow rate as measured by one flowmeter followed by injection of calibration gas at the same flow rate as measured by the other flowmeter should agree within the specified precision limits. If they do not, then there is a problem with the mass flow measurement. Each mass flowmeter shall be calibrated prior to the first test with a wet test meter and thereafter at least once each year.

12.1.4.3 Constant Temperature Bath. Capable of maintaining permeation tubes at certification temperature of 30° C within ±0.1° C.

12.2 Reagents.

12.2.1 Fuel. Hydrogen (H_2) prepurified grade or better.

12.2.2 Combustion Gas. Oxygen (O_2) research purity or better.

12.2.3 Carrier Gas. Nitrogen (N_2) prepurified grade or better.

12.2.4 Diluent. Air containing less than 0.5 ppm total sulfur compounds and less than 10 ppm each of moisture and total hydrocarbons, and filtered using MSA filters 46727 and 79030, or equivalent. Removal of sulfur compounds can be verified by injecting dilution air only, described in section 8.3.

12.2.5 Compressed Air. 60 psig for GC valve actuation.

12.2.6 Calibration Gases. Permeation tubes gravimetrically calibrated and certified at 30.0° C.

12.3 Operating Parameters. The operating parameters for the GC/FPD system are as follows: nitrogen carrier gas flow rate of 100 cc/min, exhaust temperature of 110° C, detector temperature 105° C, oven temperature of 40° C, hydrogen flow rate of 80 cc/minute, oxygen flow rate of 20 cc/minute, and sample flow rate of 80 cc/minute.

12.4 Analysis. The sample valve is actuated for 1 minute in which time an aliquot of diluted sample is injected onto the separation column. The valve is then deactivated for the remainder of analysis cycle in which time the sample loop is refilled and the separation column continues to be foreflushed. The elution time for each compound will be determined during calibration.

13. Bibliography

13.1 O'Keeffe, A. E. and G. C. Ortman. "Primary Standards for Trace Gas Analysis." Anal. Chem. 38,760 (1966).

13.2 Stevens, R. K., A. E. O'Keeffe, and G. C. Ortman. "Absolute Calibration of a Flame Photometric Detector to Volatile Sulfur Compounds at Sub-Part-Per-Million Levels." Environmental Science and Technology 3:7 (July, 1969).

13.3 Mulick, J. D., R. K. Stevens, and R. Baumgardner. "An Analytical System Designed to Measure Multiple Malodorous Compounds Related to Kraft Mill Activities." Presented at the 12th Conference on Methods in Air Pollution and Industrial Hygiene Studies, University of Southern California, Los Angeles, Calif. April 6-8, 1971.

13.4 Devonald, R. H., R. S. Serenius, and A. D. McIntyre. "Evaluation of the Flame Photometric Detector for Analysis of Sulfur Compounds." Pulp and Paper Magazine of Canada, 73,3 (March, 1972).

13.5 Grimley, K. W., W. S. Smith, and R. M. Martin. "The Use of a Dynamic Dilution System in the Conditioning of Stack Gases for Automated Analysis by a Mobile Sampling Van." Presented at the 63rd Annual APCA Meeting in St. Louis, Mo. June 14-19, 1970.

13.6 General Reference. Standard Methods of Chemical Analysis Volume III A and B Instrumental Methods. Sixth Edition. Van Nostrand Reinhold Co.

[FR Doc. 78-6633 Filed 3-14-78, 8 45 am]

FEDERAL REGISTER, VOL. 43, NO. 51

WEDNESDAY, MARCH 15, 1978

87

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 870-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Amendments to Reference Methods 1-8; Correction

AGENCY: Environmental Protection Agency.

ACTION: Correction.

SUMMARY: This document corrects typographical errors to certain Reference Methods and makes amendments to others for purposes of clarification. These Reference Methods were published as final rules in the FEDERAL REGISTER for Thursday, 42 FR 41754, August 18, 1977, in FR Doc. 77-13608.

EFFECTIVE DATE: March 23, 1978.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: After publication of revisions to Reference Methods 1-8 on August 18, 1977, we found many typographical errors. We also received comments which showed that the procedures in Reference Methods 1, 4, 6, and 7 needed additional clarification or revision. Additional explanation of the procedures to be used are provided by this correc-

tion notice. In addition to the errors in the methods themselves, two typographical errors were discovered in the preamble. On page 41754, under "Method 7," the phrase "variable wave length" is corrected to read "single and double-beam." On page 41755, under "Method 8," the word "content" (in point No. 4) is corrected to read "components."

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Analysis.

Dated: March 13, 1978.

DAVID A. HAWKINS,
Assistant Administrator for Air and Waste Management.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

APPENDIX A—REFERENCE METHODS

In Method 1 of Appendix A, Sections 2.3.1, 2.3.2, and 2.4 and Table 1-1 are amended as follows:

1. In Section 2.3.1, the word "adcording" in the second line is corrected to read "according."

2. In Section 2.3.2, insert after the first paragraph the following:

If the tester desires to use more than the minimum number of traverse points, expand the "minimum number of traverse points" matrix (see Table 1-1) by adding the extra traverse points along one or the other or both legs of the matrix; the final matrix need not be balanced. For example, if a 4x3 "minimum number of points" matrix were expanded to 36 points, the final matrix could be 9x4 or 12x3, and would not necessarily have to be 6x6. After constructing the final matrix, divide the stack cross-section into as many equal rectangular, elemental areas as traverse points, and locate a traverse point at the centroid of each equal area

3. In Section 2.4, the word "travrse" in the fifteenth line of the second paragraph is corrected to read "traverse."

4. In Table 1-1, move the words "Number of traverse points" to the left, so that they are centered above the numbers listed in the left-hand column.

In Method 2 of Appendix A, Sections 2.1, 2.2, 2.4, 3.2, 4.1, 4.1.2, 4.1.4.1, 4.1.5.2, and 6 are amended as follows;

1. In Section 2.1, "±" is inserted in front of the "5 percent" in the fourteenth line of the third paragraph.

2. In Section 2.2, "measuremen t" in the next-to-the last line of the first paragraph is corrected to read "measurement."

3. In Section 2.4, "Type X" in the fifth line is corrected to read "Type S."

4. In Section 3.2, "ma" in the first line is corrected to read "ma-."

5. In Section 4.1, "R_t" in the seventh line of the second paragraph is replaced with "D_t."

6. In Section 4.1.2, "B." is inserted between the words "other," and "Calibration."

7. In Section 4.1.4.1, "$C_{p(s)}$=Type S pilot tube coefficient" is corrected to read "$C_{p(s)}$=Type S pitot tube coefficient."

8. In Section 4.1.5.2, the words "pitot-nozzel" in the third line are corrected to read "pitot-nozzle."

9. In Section 6, Citations 9, 13, and 18 are amended as follows:

a. In No. 9, the word "Tiangle" is corrected to read "Triangle."

b. In No. 13, the "s" in "Techniques" is deleted.

c. In No. 18, the word "survey" is corrected to read "Survey."

In Method 3 of Appendix A, Sections 1.2, 3.2.4, 4.2.6.2, 6.2, and 7 are amended as follows:

1. In Section 1.2, the title ",U. S. Environmental Protection Agency." is inserted at the end of the second paragraph.

2. In Section 3.2.4, "CO" in the tenth line is corrected to read "CO_2."

3. In Section 4.2.6.2(b), the phrase "or equal to" is inserted between "than" and "15.0."

4. In Section 6.2, Equation 3-1 is corrected to read as follows:

$$\%EA = \left[\frac{\%O_2 - 0.5\%CO}{0.264\,\%N_2 - (\%O_2 - 0.5\,\%CO)}\right] 100$$

5. In Section 7, Bibliography, No. 2, the word "with" is inserted between the words "Sampling" and "Plastic."

In Method 4 of Appendix A, Sections 2.1.2, 2.2.1, 2.2.3, 2.3.1, 3.1.8, 3.2.1, 3.3.1, 3.3.3, 3.3.4, and Figure 4-2 are amended as follows:

1. In Section 2.1.2, the word "neasurement" in the third line of the third paragraph is corrected to read "measurement."

2. In Section 2.2.1, the word "travers" in the sixth line is corrected to read "traverse."

3. In Section 2.2.3, the work "eak" in the last sentence is corrected to read "leak."

4. In Figure 4-2, the word "ocation" in the second line on top of the figure, is corrected to read "Location."

5. In Section 2.3.1, "M_w" is changed to read "M_w" and "P_w" is changed to read "ρ_w."

6. In Section 3.1.8, "31 pm" is corrected to read "3 1pm".

7. In Section 3.2.1. delete all of first paragraph except the first sentence and insert the following:

Leak check the sampling train as follows: Temporarily insert a vacuum gauge at or near the probe inlet; then, plug the probe inlet and pull a vacuum of at least 250 mm Hg (10 in. Hg). Note, the time rate of change of the dry gas meter dial; alternatively, a rotameter (0-40 cc/min) may be temporarily attached to the dry gas meter outlet to determine the leakage rate. A leak rate not in excess of 2 percent of the average sampling rate is acceptable.

NOTE.—Carefully release the probe inlet plug before turning off the pump.

8. In Section 3.3.1, add the following definition to the list:

Y=Dry gas meter calibration factor.

Also, "o_w" is corrected to read "ρ_w".

9. In Section 3.3.3, Equation 4-6 is corrected to read as follows:

$$V_{m(std)} = V_m Y \left(\frac{P_m}{P_{std}}\right)\left(\frac{T_{std}}{T_m}\right) = K_2 Y \frac{V_m P_m}{T_m}$$

10. In Section 3.3.4, Equation 4-7 is corrected to read as follows:

$$B_{ws} = \frac{V_{wc(std)}}{V_{wc(std)} + V_{m(std)}} + B_{wm} \frac{V_{wc(std)}}{V_{wc(std)} + V_{m(std)}} + (0.025)$$

In Method 5 of Appendix A, Sections 2.1.1, 2.2.4, 4.1.2, 4.1.4.2, 4.2, 6.1, 6.3, 6.11.1, and 6.11.2 are amended as follows:

1. In Section 2.1.1, the word "proble" in the fourth line is corrected to read "probe."

2. In Section 2.2.4, "polO-" is corrected to read "poly-".

3. In Section 4.1.2, the sentence "The sampling time at each point shall be the same." is inserted at the end of the fifth paragraph.

4. In Section 4.1.4.2, the word "It" in the seventh line is corrected to read "it."

5. In Section 4.2, the word "nylon" in the seventh, ninth, and thirteenth paragraphs is corrected to read "Nylon."

6. In Section 6.1 Nomenclature, "C_a=Acetone blank residue concentrations, mg/g" is corrected to read "C_a=Acetone blank residue concentration, mg/g" and "V_a" is changed to read "v_a."

7. In Section 6.3, page 41782, "m_1=0.3858 °K/mm Hg for metric units" is corrected to read "K_1=0.3858 °K/mm Hg for metric units."

8. In Section 6.11.1, Equation 5-7 is corrected to read as follows:

$$t = \frac{100\,T_s\,[K_3 V_{lc} + (V_m Y/T_m)(P_{bar} + \Delta H/13.6)]}{60\,\theta_s\,P_s\,A_n}$$

9. In Section 6.11.2, the second form of Equation 5-8 is corrected to read as follows:

$$= K_4 \frac{T_s\,V_{m(std)}}{P_s\,v_s\,A_n\,\theta\,(1-B_{ws})^2}$$

In Method 6 of Appendix A, Sections 2.1, 2.1.6, 2.1.7, 2.1.8, 2.1.11, 2.1.12, 2.3.2, 3.3.4, 4.1.2, 4.1.3, and 5.1.1 are amended as follows:

1. In Section 2.1, the word "perioxide" in the fourth line of the second paragraph is corrected to read "peroxide."

2. In Section 2.1.6, the word "siliac" in the third line is corrected to read "silica."

3. In Section 2.1.7, the word "value", which appears twice is corrected to read "valve."

4. In Section 2.1.8, the word "disphragm" is corrected to read "diaphragm" and the word "surge" is inserted between the words "small" and "tank."

5. In Section 2.1.11, the word "ameroid" is corrected to read "aneroid."

6. In Section 2.1.12, the phrase "and Rotameter." is inserted after the phrase "Vacuum Gauge" and the phrase "and 0–40 cc/min rotameter" is inserted between the words "gauge" and ", to."

7. In Section 2.3.2, the phrase "and 100-ml size" is corrected to read "and 1000-ml size."

8. In Section 3.3.4, the word "sopropanol" in the fourth line is corrected to read "isopropanol."

9. In Section 4.1.2, delete the last sentence of the last paragraph. Also delete the second paragraph and replace it with the following paragraphs:

Temporarily attach a suitable (e.g., 0–40 cc/min) rotameter to the outlet of the dry gas meter and place a vacuum gauge at or near the probe inlet. Plug the probe inlet, pull a vacuum of at least 250 mm Hg (10 in. Hg), and note the flow rate as indicated by the rotameter. A leakage rate not in excess of 2 percent of the average sampling rate is acceptable.

NOTE: Carefully release the probe inlet plug before turning off the pump.

It is suggested (not mandatory) that the pump be leak-checked separately, either prior to or after the sampling run. If done prior to the sampling run, the pump leak-check shall precede the leak check of the sampling train described immediately above; if done after the sampling run, the pump leak-check shall follow the train leak-check. To leak check the pump, proceed as follows: Disconnect the drying tube from the probe-impinger assembly. Place a vacuum gauge at the inlet to either the drying tube or the pump, pull a vacuum of 250 mm (10 in.) Hg, plug or pinch off the outlet of the flow meter and then turn off the pump. The vacuum should remain stable for at least 30 seconds.

10. In Section 4.1.3, the sentence "If a leak is found, void the test run" on the sixteenth line is corrected to read "If a leak is found, void the test run, or use procedures acceptable to the Administrator to adjust the sample volume for the leakage."

11. In Section 5.1.1, the word "or" on the sixth line is corrected to read "of."

In Method 7 of Appendix A, Sections 2.3.2, 2.3.7, 4.2, 4.3, 5.2.1, 5.2.2, 6 and 7 are amended as follows:

1. In Section 2.3.2, a semicolon replaces the comma between the words "step" and "the."

2. In Section 2.3.7, the phrase "(one for each sample)" in the first line is corrected to read "(one for each sample and each standard)."

3. In Section 4.2, the letter "n" in the seventh line is corrected to read "in."

4. In Section 4.3, the word "poylethylene" in the seventeenth line is corrected to read "polyethylene."

5. In Section 5.2.1, delete the entire section and insert the following:

Optimum Wavelength Determination. Calibrate the wavelength scale of the spectrophotometer every 6 months. The calibration may be accomplished by using an energy source with an intense line emission such as a mercury lamp, or by using a series of glass filters spanning the measuring range of the spectrophotometer. Calibration materials are available commercially and from the National Bureau of Standards. Specific details on the use of such materials should be supplied by the vendor; general information about calibration techniques can be obtained from general reference books on analytical chemistry. The wavelength scale of the spectrophotometer must read correctly within ± 5 nm at all calibration points; otherwise, the spectrophotometer shall be repaired and recalibrated. Once the wavelength scale of the spectrophotometer is in proper calibration, use 410 nm as the optimum wavelength for the measurement of the absorbance of the standards and samples.

Alternatively, a scanning procedure may be employed to determine the proper measuring wavelength. If the instrument is a double-beam spectrophotometer, scan the spectrum between 400 and 415 nm using a 200 μg NO_2 standard solution in the sample cell and a blank solution in the reference cell. If a peak does not occur, the spectrophotometer is probably malfunctioning and should be repaired. When a peak is obtained within the 400 to 415 nm range, the wavelength at which this peak occurs shall be the optimum wavelength for the measurement of absorbance of both the standards and the samples. For a single-beam spectrophotometer, follow the scanning procedure described above, except that the blank and standard solutions shall be scanned separately. The optimum wavelength shall be the wavelength at which the maximum difference in absorbance between the standard and the blank occurs.

6. In Section 5.2.2, delete the first seven lines and insert the following:

Determination of Spectrophotometer Calibration Factor K_c. Add 0.0 ml, 2 ml, 4 ml, 6 ml, and 8 ml of the KNO_3 working standard solution (1 ml = 100 μg NO_2) to a series of five 50-ml volumetric flasks. To each flask, add 25 ml of absorbing solution, 10 ml deionized, distilled water, and sodium hydroxide (1 N) dropwise until the pH is between 9 and 12 (about 25 to 35 drops each). Dilute to the mark with deionized, distilled water. Mix thoroughly and pipette a 25-ml aliquot of each solution into a separate porcelain evaporating dish.

7. In Section 6.1, the word "Hass" in the tenth line is corrected to read "Mass."

8. In Section 7, the word "Vna" in (1) is corrected to read "Van." The word "drtermination" in (6) is corrected to read "Determination."

In Method 8 of Appendix A, Sections 1.2, 2.32, 4.1.4, 4.2.1, 4.3.2, 6.1, and 6.7.1 are amended as follows:

1. In Section 1.2, the phrase "U.S. EPA," is inserted in the fifth line of the second paragraph between the words "Administrator," and "are." Also, delete the third paragraph and insert the following:

Filterable particulate matter may be determined along with SO_2 and SO_3 (subject to the approval of the Administrator) by inserting a heated glass fiber filter between the probe and isopropanol impinger (see Section 2.1 of Method 6). If this option is chosen, particulate analysis is gravimetric only; H_2SO_4 acid mist is not determined separately.

2. In Section 2.3.2, the word "Burrette" is corrected to read "Burette."

3. In Section 4.1.4, the stars "* * *" are corrected to read as periods ". . .".

4. In Section 4.2.1, the word "het" on the eighth line of the second paragraph is corrected to read "the."

5. In Section 4.3.2, the number "40" is inserted in the fourth line between the words "Add" and "ml."

6. In Section 6.1, Nomenclature, the following are corrected to read as shown with subscripts "$C_{H_2SO_4}$, C_{SO_2}, P_{bar}, P_{std}, T_{std}, $V_{m(std)}$, and V_{soln}."

7. In Section 6.7.1, Equation 8-4 is corrected to read as follows:

$$I = \frac{100\ T_s\ [K_4\ V_{lc} + (V_m Y / T_m)(P_{bar} + \Delta H/13.6)]}{60\ \theta\ v_s\ P_s\ A_n}$$

(Secs. 111, 114, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7414, 7601).)

[FR Doc. 78-7686 Filed 3-22-78; 8:45 am]

FEDERAL REGISTER, VOL. 43, NO. 57

THURSDAY, MARCH 23, 1978

88

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 841-6]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Basic Oxygen Process Furnaces: Opacity Standard

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This action establishes an opacity standard for basic oxygen process furnace (BOPF) facilities. In March 1974 (39 FR 9308), EPA promulgated a standard limiting the concentration of particulate matter emissions from BOPF's, however, an opacity standard was not promulgated at that time becuase of insufficient data to define variations in visible emissions from well-controlled facilities. An opacity standard had been proposed on June 11, 1973 (38 FR 15406) and was reproposed on March 2, 1977 (42 FR 12130). Additional data have provided the basis for the opacity standard which will help insure that control equipment is properly operated and maintained. Like the concentration standard, this opacity standard applies to BOPF facilities the construction or modification of which was commenced after June 11, 1973 since both standards were proposed on that date.

EFFECTIVE DATE: April 13, 1978.

ADDRESS. The public comments received may be inspected and copies at the Public Information Reference Unit (EPA Library), Room 2922, 401 M Street SW., Washington, D.C.

FOR FURTHER INFORMATION:

Don R. Goodwin, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone No. 919-541-5271.

SUPPLEMENTARY INFORMATION:

COMMENTS

A total of 10 comment letters were received—4 from industry, 5 from governmental agencies, and 1 from an environmental interest group. The significant comments received and EPA's responses are presented here.

Three commenters expressed the need for establishing an opacity standard for fugitive emissions. Fugitive emissions occur when off gases from the furnace are not completely captured by the furnance hood (which ducts waste gases to the control device). During some operations, the fugitive emissions can be significant. The fugitive emissions escape to the atmosphere through roof monitors.

EPA recognizes that fugitive emissions from BOPF shops are an important problem. However, it was not within the scope of this evaluation to consider an opacity standard for fugitive emissions. The particulate concentration standard covers only stack emissions. The purpose of the opacity standard for stack emissions is to serve as a means for enforcement personnel to insure that the particulate matter control system is being properly operated and maintained. EPA will be reviewing the standards of performance for new BOPF's in accordance with the 1977 amendments to the Clean Air Act. This review will address the need for limits on fugitive emissions as well as any revisions of the particulate concentration and opacity standards.

It should be noted that the absence of standards for fugitive emissions under this part does not preclude the establishment of standards as part of the new source review (NSR) and prevention of significant deterioration (PSD) programs of the Agency or as part of the programs of State and local agencies.

Two commenters questioned how the standard would apply to BOPF shops that have plenums to exhaust the emissions from more than one furnace into a single control device. They reasoned that if the production cycles overlap, it would be impossible to determine when an opacity of greater than 10 percent (but less than 20 percent) was attributable to a violation by one furnace or an acceptable emission by another furnace during oxygen blowing. EPA was aware that this situation would occur during the development of the opacity standard. Several of the plants at which visible emission tests were conducted had a single control device serving more than one furnace. The furnace production cycle data were recorded and it was not difficult to correlate the opacity data with the production cycle. Enforcement personnel can evaluate a plant's operation (length of cycle, degree of overlapping, etc.) prior to completing an inspection and correctly identify probable violations from a correlation of their opacity readings with the plant's production and monitoring records. Correlation of the data and the synchronization requirements described later will prevent the enforcement problems described by the commenters. Promulgation of an unduly complex standard that addresses the peculiarities of every BOPF installation would complicate rather than simplify enforcement. Although it is unlikely that two furnaces will be si-

multaneously started on a blow, production data should be examined for such peculiarities before drawing any conclusions from the opacity data.

Other issues raised include the effect of oxygen "reblows" on the standard and a request for a more lenient monitoring requirement. One industry commenter claimed that there would be a "significant" number of production cycles with more than one opacity reading greater than 10 percent due to the blowing of additional oxygen (after the initial oxygen blow) into a furnace to obtain the proper composition. The opacity standard, however, is based on 73 hours of BOPF operation during which numerous reblows occurred. It was found that although the opacities could be very large at these times, they were of short enough duration that the six-minute average was still 10 percent or less.

EPA agrees with the comment that the requirement for reporting of instantaneous scrubber differential and water supply pressures that are less than 10 percent of the average maintained during the most recent performance test needs further clarification. The requirement has been revised so that any deviation of more than 10 percent over a three hour averaging period must be reported. The three hour averaging period was chosen since it is the minimum duration of a performance test. Thus instantaneous monitoring device measurements caused by routing process fluctuations will not be reported. The reports needed are the periods of time when the average scrubber pressure drop is below the level used to demonstrate compliance at the time of the performance test. In addition, the requirement for a water pressure monitor has been retained (despite the comment that it will not indicate a plugged water line) since it will perform the function of assuring that the water pumps have not shut down. A flow monitoring device was not specified because they are susceptible to plugging.

To provide for the use of certain partial combustion systems on BOPFs, new requirements have been added to the monitoring section and two clarifications added to the test methods and procedures section. A partial combustion system uses a closed hood to limit gas combustion and exhaust gas volumes. To recover combustible exhaust gases, the system may be designed to duct its emissions away from the stack to a gas holding tank during part of the steel production cycle. Steel plants in this country may begin to make more use of this approach due to its significant energy benefits. This type of control/recovery system presents two problems for enforcement personnel. First is the problem of knowing when the diversion of exhaust gases from the stack occurs The new requirements of paragraphs (a), (b)(3), and (b)(4) of §60.143 address this question. Second is the problem of how to sample or observe stack emissions. New provisions under §60.144 clarify this question for determining the opacity of emissions (paragraph (a)(5)) and for determining the concentration of emissions (paragraph (c)).

In addition to addressing the problem posed by exhaust gas diversion, the new requirements of paragraphs (a), (b)(3), and (b)(4) of §60.143 are also designed to minimize errors in recording the time and duration of the steel production cycle for all types of BOPFs. Accurate records are essential for determining compliance with the opacity standard. Likewise the synchronization of daily logs with the chart recorders of monitoring devices is necessary for determining that acceptable operation and maintenance procedures are being used as required by paragraph (d) of §60.11.

An alternative to the manual method of synchronization under paragraph (b)(3) of §60.143 which may minimize costs of this requirement would be to have the chart recorder automatically mark the beginning and end of the steel production cycle and any period of gas diversion from the stack. Such marking could be electrically relayed from the production equipment and exhaust duct damper operation in order to be fully automatic. Source owners or operators who wish to employ this method or equivalent methods in lieu of the synchronization procedure prescribed by the regulations may submit their plans to the Administrator for approval under paragraph 60.13(i).

The concentration standard promulgated in March, 1974, applies to both top and bottom-blown BOPFs. In developing the proposed opacity standard, data from both types of BOPFs were considered. Scrubber-controlled top and bottom-blown BOPFs were demonstrated capable of meeting the opacity limits proposed and here promulgated. Thus the promulgated opacity standard applies to bottom as well as top-blown BOPFs.

Although there was no announced intentions to utilize electrostatic precipitators (ESPs) as a control device (rather than venturi scrubbers), during the development of the proposed standard, one industry commenter asserted that ESPs may become more attractive in the future, especially in the semi-arid regions of the West where the water and energy demands of scrubbers are not easily met. If a BOPF furnace is constructed with an ESP control device, the establishment of a site-specific opacity standard may be necessary. Upon request by the owner or operator of the BOPF furnace, a determination will be made by EPA pursuant to §60.11(e) if performance tests demonstrate compliance with the mass concentration standard.

Miscellaneous

It should be noted that standards of performance for new sources established under section 111 of the Act reflect emission limits achievable with the best adequately demonstrated technological system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements). State implementation plans (SIPs) approved or promulgated under section 110 of the Act, on the other hand, must provide for the attainment and maintenance of national ambient air quality standards (NAAQS) designed to protect public health and welfare. For that purpose, SIPs must in some cases require greater emission reductions than those required by standards of performance for new sources. Section 173(2) of the Clean Air Act, requires, among other things, that a new or modified source constructed in an area which exceeds the NAAQS must reduce emissions to the level which reflects the "lowest achievable emission rate" for such category of source, unless the owner or operator demonstrates that the source cannot achieve such an emission rate. In no event can the emission rate exceed any applicable standard of performance.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area which falls under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology The term "best available control technology" (BACT) means "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facilities through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act."

Standards of performance should not be viewed as the ultimate in achievable emission control and should not preclude the imposition of a more stringent emission standard, where appropriate. For example, while cost of achievement may be an important factor in determining standards of performance applicable to all areas of the country (clean as well as dirty), costs must be accorded for less weight in determining the "lowest achievable emission rate for the new or modified sources locating in areas violating statutorily-mandated health and welfare standards. Although there may be emission control technology available that can reduce emissions below the level required to comply with standards of performance, this technology might be selected as the basis of standards of performance due to costs associated with its use. This in no way should preclude its use in situations where cost is a lesser consideration, such as determination of the "lowest achievable emission rate." Furthermore, since partial combustion systems and bottom blown BOPFs have been shown to be inherently less polluting, more stringent emission limits may be placed on such sources for the purposes of defining "best available control technology" (under Prevention of Significant Deterioration regulation) and "lowest achievable emission rate" in non-attainment areas.

In addition, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under secton 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

The effective date of this regulation is (date of publication), because section 111(b)(1)(B) of the Clean Air Act provides that standards of performance or revisions thereof become effective upon promulgation.

The opacity standard, like the concentration standard, applies to BOPFs which commenced construction or modification after June 11, 1973. That is the date on which both standards were originally proposed. The opacity standard will add no new control burden to the sources affected, but will provide an effective means of monitoring the compliance of these facilities. The relief provided under § 60.11(e) insures that the opacity standard requires no greater reduction in emissions than the concentration standard.

NOTE.—The Environmental Protection Agency has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Analysis under Executive Orders 11821 and 11949 and OMB Circular A-107.

Dated: April 4, 1978.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

Subpart N—Standards of Performance for Iron and Steel Plants

1. Section 60.141 is amended by adding paragraph (c) as follows:

§ 60.141 Definitions.

* * * * *

(c) "Startup means the setting into operation for the first steel production cycle of a relined BOPF or a BOPF which has been out of production for a minimum continuous time period of eight hours.

2. Section 60.142 is amended by adding paragraph (a)(2) as follows:

§ 60.142 Standard for particulate matter.

(a) * * *

(2) Exit from a control device and exhibit 10 percent opacity or greater, except that an opacity of greater than 10 percent but less than 20 percent may occur once per steel production cycle.

(Secs 111, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7601).)

3. A new § 60.143 is added as follows:

§ 60.143 Monitoring of operations.

(a) The owner or operator of an affected facility shall maintain a single time-measuring instrument which shall be used in recording daily the time and duration of each steel production cycle, and the time and duration of any diversion of exhaust gases from the main stack servicing the BOPF.

(b) The owner or operator of any affected facility that uses venturi scrubber emission control equipment shall install, calibrate, maintain, and continuously operate monitoring devices as follows:

(1) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±250 Pa (±1 inch water).

(2) A monitoring device for the continous measurement of the water supply pressure to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ±5 percent of the design water supply pressure. The monitoring device's pressure sensor or pressure tap must be located close to the water discharge point. The Administrator may be consulted for approval of alternative locations for the pressure sensor or tap.

(3) All monitoring devices shall be synchronized each day with the time-measuring instrument used under paragraph (a) of this section. The chart recorder error directly after synchronization shall not exceed 0.08 cm (1/32 inch).

(4) All monitoring devices shall use chart recorders which are operated at a minimum chart speed of 3.8 cm/hr (1.5 in/hr).

(5) All monitoring devices are to be recalibreated annually, and at other times as the Administrator may require, in accordance with the proceduces under § 60.13(b)(3).

(c) Any owner or operator subject to requirements under paragraph (b) of this section shall report for each calendar quarter all measurements over any three-hour period that average more than 10 percent below the average levels maintained during the most recent performance test conducted under § 60.8 in which the affected facility demonstrated compliance with the standard under § 60.142(a)(1). The accuracy of the respective measurements, not to exceed the values specified in paragraphs (b)(1) and (b)(2) of this section, may be taken into consideration when determining the measurement results that must be reported.

4. Section 60.144 is amended by adding paragraphs (a)(5) and (c) as follows:

§ 60.144 Test methods and procedures.

(a) * * *

(5) Method 9 for visible emissions. For the purpose of this subpart, opacity observations taken at 15-second intervals immediately before and after a diversion of exhaust gases from the stack may be considered to be consecutive for the purpose of computing an average opacity for a six-minute period. Observations taken during a diversion shall not be used in determining compliance with the opacity standard.

* * * * *

(c) Sampling of flue gases during each steel production cycle shall be discontinued whenever all flue gases are diverted from the stack and shall be resumed after each diversion period.

(Secs 111, 114, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7414, 7601).)

[FR Doc. 78-9879 Filed 4-12-78; 8:45 am]

89

Title 40—Protection of Environment

[FRL 882-6]

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

Subchapter C—Air Programs

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority to State/Local Air Pollution Control Agencies in Arizona, California, and Nevada

AGENCY: Environmental Protection Agency.

ACTION: Final Rulemaking.

SUMMARY: The Environmental Protection Agency (EPA) is amending 40 CFR 60.4 *Address* by adding addresses of agencies to reflect new delegations of authority from EPA to certain state/local air pollution control agencies in Arizona, California, and Nevada. EPA has delegated authority to these agencies, as described in a notice appearing elsewhere in today's FEDERAL REGISTER, in order to implement and enforce the standards of performance for new stationary sources.

EFFECTIVE DATE: May 16, 1978.

FOR FURTHER INFORMATION CONTACT:

Gerald Katz (E-4-3), Environmental Protection Agency, 215 Fremont Street, San Francisco, Calif. 94105, 415-556-8005.

SUPPLEMENTARY INFORMATION: Pursuant to delegation of authority for the standards of performance for new stationary sources (NSPS) to State/Local air pollution control agencies in Arizona, California, and Nevada from March 30, 1977 to January 30, 1978, EPA is today amending 40 CFR 60.4 *Address,* to reflect these actions. A Notice announcing this delegation is published elsewhere in today's FEDERAL REGISTER. The amended § 60.4 is set forth below. It adds the address of the air pollution control agencies, to which must be addressed all reports, requests, applications, submittals, and communications pursuant to this part by sources subject to the NSPS located within these agencies' jurisdictions.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation actions which are reflected in this administrative amendment were effective on the dates of delegation and it serves no purpose to delay the technical change on these additions of the air pollution control agencies' addresses to the Code of Federal Regulations.

(Sec. 111, Clean Air Act, as amended (42 U.S.C. 7411).)

Dated: April 5, 1978.

SHEILA M. PRINDIVILLE,
Acting Regional Administrator, Environmental Protection Agency, Region IX.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising subparagraphs D, F, and DD to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(D) Arizona:

Maricopa County Department of Health Services, Bureau of Air Pollution Control, 1825 East Roosevelt Street, Phoenix, AZ 85006.

Pima County Health Department, Air Quality Control District, 151 West Congress, Tucson, AZ 85701.

* * * * *

(F) California:

Bay Area Air Pollution Control District, 939 Ellis Street, San Francisco, CA 94109.

Del Norte County Air Pollution Control District, Courthouse, Crescent City, CA 95531.

Fresno County Air Pollution Control District, 515 S. Cedar Avenue, Fresno, CA 93702.

Humboldt County Air Pollution Control District, 5600 S. Broadway, Eureka, CA 95501.

Kern County Air Pollution Control District, 1700 Flower Street (P.O. Box 997), Bakersfield, CA 93302.

Madera County Air Pollution Control District, 135 W. Yosemite Avenue, Madera, CA 93637.

Mendocino County Air Pollution Control District, County Courthouse, Ukiah, CA 94582.

Monterey Bay Unified Air Pollution Control District, 420 Church Street (P.O. Box 487), Salinas, CA 93901.

Northern Sonoma County Air Pollution Control District, 3313 Chanate Road, Santa Rosa, CA 95404.

Sacramento County Air Pollution Control District, 3701 Branch Center Road, Sacramento, CA 95827.

San Diego County Air Pollution Control District, 9150 Chesapeake Drive, San Diego, CA 92123.

San Joaquin County Air Pollution Control District, 1601 E. Hazelton Street (P.O. Box 2009), Stockton, CA 95201.

Santa Barbara County Air Pollution Control District, 4440 Calle Real, Santa Barbara, CA 93110.

Shasta County Air Pollution Control District, 1855 Placer Street, Redding, CA 96001.

South Coast Air Quality Management District, 9420 Telstar Avenue, El Monte, CA 91731.

Stanislaus County Air Pollution Control District, 820 Scenic Drive, Modesto, CA 95350.

Trinity County Air Pollution Control District, Box AJ, Weaverville, CA 96093.

Ventura County Air Pollution Control District, 625 E. Santa Clara Street, Ventura, CA 93001.

* * * * *

(DD) Nevada:

Nevada Department of Conservation and Natural Resources, Division of Environmental Protection, 201 South Fall Street, Carson City, NV 89710.

Clark County County District Health Department, Air Pollution Control Division, 625 Shadow Lane, Las Vegas, NV 89106.

Washoe County District Health Department, Division of Environmental Protection, 10 Kirman Avenue, Reno, NV 89502.

* * * * *

[FR Doc. 78-13011 Filed 5-15-78; 8:45 am]

FEDERAL REGISTER, VOL. 43, NO. 95

TUESDAY, MAY 16, 1978

90

Title 40—Protection of the Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 907-2]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Grain Elevators

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The standards limit emissions of particulate matter from new, modified, and reconstructed grain elevators. The standards implement the Clean Air Act and are based on the Administrator's determination that emissions from grain elevators contribute significantly to air pollution. The intended effect of these standards is to require new, modified, and reconstructed grain elevators to use the best demonstrated system of continuous emission reduction, considering costs, nonair quality health, environmental and energy impacts.

EFFECTIVE DATE: August 3, 1978.

ADDRESSES: Copies of the standards support documents are available on request from the U.S. EPA Library (MD-35), Research Triangle Park, N.C. 27711, telephone 919-541-2777 or (FTS) 629-2777. The requester should specify "Standards Support and Environmental Impact Statement, Volume 1: Proposed Standards of Performance for Grain Elevator Industry," (EPA-450-77-001a) and/or "Standards Support and Environmental Impact Statement, Volume 2: Promulgated Standards of Performance for Grain Elevator Industry," (EPA-450/2-77-001b). Copies of all comment letters received from interested persons participating in this rulemaking are available for inspection and copying during normal business hours at EPA's Public Information Reference Unit, Room 2922, EPA Library, 401 M Street SW., Washington, D.C.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Director Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: On January 13, 1977, standards of performance were proposed for the grain elevator industry (42 FR 2842) under the authority of section 111 of the Clean Air Act. Public comments were requested on the proposal in the FEDERAL REGISTER publication. Approximately 2,000 comments were received from grain elevator operators, vendors of equipment, Congressmen, State and local air pollution control agencies, other Federal agencies, and individual U.S. citizens. Most of these comments reflected a general misunderstanding of the proposed standards and were very general in nature. A number of comments, however, contained a significant amount of useful data and information. Due to the time required to review these comments, the standards were suspended on June 24, 1977. This action was necessary to avoid creating legal uncertainties for those grain elevator operators who might have undertaken various expansion or alteration projects before promulgation of final standards.

On August 7, 1977, Congress amended the Clean Air Act. These amendments contained a provision specifically exempting country grain elevators with less than 2.5 million bushels of grain storage capacity from standards of performance developed under section 111 of the Act.

Following review of the public comments, a draft of the final standards was developed consistent with the adopted amendments to the Clean Air Act. A report responding to the major issues raised in the public comments and containing the draft final standards was mailed on August 15, 1977, to each individual, agriculture association, equipment vendor, State and local government, and member of Congress who submitted comments. Comments were requested on the draft final standards by October 15, 1977. One hundred comments were received, and the final standards reflect a thorough evaluation of these comments.

The proposed standards are reinstated elsewhere in this issue of the FEDERAL REGISTER.

THE STANDARDS

The promulgated standards apply only to new, modified, or reconstructed grain elevators with a permanent grain storage capacity of more than 88,100 m^3 (ca. 2.5 million U.S. bushels) and new, modified, or reconstructed grain storage elevators at wheat flour mills, wet corn mills, dry corn mills (human consumption), rice mills, or soybean oil extraction plants with a permanent grain storage capacity of more than 35,200 m^3 (ca. 1 million U.S. bushels).

The standards limit particulate matter emissions from nine types of affected facilities at grain elevators by limiting the visibility of emissions released to the atmosphere. The affected facilities are each truck loading station, truck unloading station, railcar loading station, railcar unloading station, barge or ship loading station, barge or ship unloading station, grain dryer, all grain handling operations and each emission control device.

The standards can be summarized as follows:

(a) Truck loading station—visible emissions may not exceed 10 percent opacity.

(b) Truck unloading station, railcar loading station, and railcar unloading station—visible emissions may not exceed 5 percent opacity.

(c) Ship or barge loading station—visible emissions may not exceed 20 percent opacity.

(d) Ship or barge unloading station—specified equipment or its equivalent must be used.

(e) Grain dryer—visible emissions may not exceed 0 percent opacity.

(f) All grain handling operations—visible emissions may not exceed 0 percent opacity.

(g) Emission control devices—visible emissions may not exceed 0 percent opacity; and the concentration of particulate matter in the exhaust gas discharged to the atmosphere may not exceed 0.023 g/dscm (ca. 0.01 gr/dscf).

These standards are different from those proposed in the following areas. The visible emission limits for truck unloading stations and railcar loading and unloading stations have been increased from 0 percent opacity to 5 percent opacity. The visible emission limit for barge and ship loading has been increased from 10 percent opacity during normal loading and 15 percent opacity during "topping off" loading, to 20 percent opacity during all loading operations. The applicability of the visible emission standards for column grain dryers has been narrowed from dryers with perforated plate hole sizes of greater than 0.084 inch diameter to dryers with perforated plate hole sizes of greater than 0.094 inch diameter.

The August 1977 amendments to the Clean Air Act authorize the promulgation of design, equipment, work practice, or operational standards if development of a numerical emission limit is not feasible. Numerical emission limits may not be feasible where emissions are not confined or where emissions cannot be measured due to technological or economic limitations. Observation of visible emissions at barge unloading stations led to the conclusion that a numerical emission limit is not feasible for this facility. The visible emissions data showed an extremely wide range with some 6 minute averages above 65 percent opacity. Because of this wide range of visible emissions, an opacity numerical emission limit cannot be established that would ensure the use of the best

system of continuous emission reduction. An equipment standard, therefore, rather than an emission standard is being promulgated for barge and ship unloading stations.

Another change from the proposed standards is that section 60.14 (modification) of the general provisions has been clarified to ensure that only capital expenditures which are spent directly on an affected facility are used to determine whether the annual asset guideline repair allowance percentage is exceeded. The annual asset guideline repair allowance percentage has been defined to be 6.5 percent.

The remaining change from the proposed standards is that four types of alterations at grain elevators have been exempted from consideration as modifications. The exempted alterations are:

(1) The addition of gravity load-out spouts to existing grain storage or grain transfer bins.

(2) The installation of automatic grain weighing scales.

(3) Replacement of motor and drive units driving existing grain handling equipment.

(4) The installation of permanent storage capacity with no increase in hourly grain handling capacity.

Environmental and Economic Impacts

The promulgated standards will reduce uncontrolled particulate matter emission from new grain elevators by more than 99 percent and will reduce particulate matter emissions by 70 to 90 percent compared to emission limits contained in State or local air pollution regulations. This reduction in emissions will result in a significant reduction of ambient air concentration levels of particulate matter in the vicinity of grain elevators. The maximum 24-hour average ambient air particulate matter concentration at a distance of 0.3 kilometer (km) from a typical grain elevator, for example, will be reduced by 50 to 80 percent below the ambient air concentration that would result from control of emissions to the level of the typical State or local air pollution regulations.

Several of the changes to the proposed standards reduce the estimated primary impact of the proposed standards in terms of reducing emissions of particulate matter from grain elevators. The promulgated standards, for example, apply only to large grain elevators. These changes will permit more emissions of particulate matter to the atmosphere. It was estimated that the proposed standards would have reduced national particulate matter emissions by approximately 21,000 metric tons over the next 5 years; it is now estimated that the promulgated standards will reduce particulate matter emissions by 11,000 metric tons over the next 5 years.

The secondary environmental impacts associated with the promulgated standards will be a small increase in solid waste handling and disposal and a small increase in noise pollution. A relatively minor amount of particulate matter, sulfur dioxide and nitrogen oxide emissions will be discharged into the atmosphere from steam/electric power plants supplying the additional electrical energy required to operate the emission control devices needed to comply with the promulgated standards. The energy impact associated with the promulgated standards will be small and will lead to an increase in national energy consumption in 1981 by the equivalent of only 1,600 m^3 (ca. 10,000 barrels) per year of No. 6 fuel oil.

Based on information contained in the comments submitted during the public comment periods, approximately 200 grain terminal elevators and grain storage elevators at grain processing plants will be covered by the promulgated standards over the next 5 years. The total incremental costs required to control emissions at these grain elevators to comply with the promulgated standards, above the costs necessary to control emissions at these elevators to comply with State or local air pollution control regulations, is $15 million in capital costs over this 5-year period and $3 million in annualized costs in the fifth year. Based on this estimate of the national economic impact, the promulgated standards will have no significant effect on the supply and demand for grain products, or on the growth of the domestic grain industry.

Public Participation

Prior to proposal of the standards, interested parties were advised by public notice in the Federal Register of a meeting of the National Air Pollution Control Techniques Advisory Committee. In addition, copies of the proposed standards and the Standards Support and Environmental Impact Statement (SSEIS) supporting these standards were distributed to members of the grain elevator industry and several environmental groups at the time of proposal. The public comment period extended from January 13, to May 14, 1977. During this period 1,817 comments were received from grain elevator operators, vendors of equipment, Congressmen, State and local air pollution control agencies, other Federal agencies, and individual U.S. citizens.

Due to the time required to review these comments, the proposed standards were suspended on June 24, 1977. This action was necessary to avoid creating legal uncertainties for those grain elevator operators who might have undertaken various expansion or alteration projects before promulgation of final standards.

Following review of the public comments, a draft of the final standards was developed consistent with the August, 1977, amendments to the Clean Air Act. A report responding to the major issues raised in the public comments and containing the draft final standards was mailed on August 15, 1977, to each individual, agriculture association, equipment vendor, State and local government, and member of Congress who submitted comments. Comments were requested on the draft final standards by October 15, 1977.

One hundred and one comments were received and the final standards reflect a thorough evaluation of these comments. Several comments resulted in changes to the proposed standards. A detailed discussion of the comments and changes made to the proposed standards is contained in volume 2 of the SSEIS, which was distributed along with a copy of the final standards to all interested parties prior to today's promulgation of final standards.

Significant Comments

Most of the comment letters received by EPA contained multiple comments. The most significant comments and changes made to the proposed standards are discussed below:

NEED FOR STANDARDS

Numerous commenters questioned whether grain elevators should be regulated since the industry is a small contributor to nationwide emissions of particulate matter and grain dust is not hazardous or toxic.

The standards were proposed under section 111 of the Clean Air Act. This section of the act requires that standards of performance be established for new stationary sources which contribute to air pollution. Existing sources are not affected unless they are reconstructed, or modified in such a way as to increase emissions. The overriding purpose of standards of performance is to prevent new air pollution problems from developing by requiring maximum feasible control of emissions from new, modified, or reconstructed sources at the time of their construction. This is helpful in attaining and maintaining the National Ambient Air Quality Standard (NAAQS) for suspended particulate matter.

The Report of the Committee on Public Works of the United States Senate in September 1970 (Senate Report No. 91-1196), listed grain elevators as a source for which standards of performance should be developed. In addition, a study of 200 industrial cat-

egories of sources, which were evaluated to develop a long-range plan for setting standards of performance for particulate matter, ranked grain elevators relatively high. The categories were ranked in order of priority based on potential decrease in emissions. Various grain handling operations ranked as follows: Grain processing—4; grain transfer—6; grain cleaning and screening—8; and grain drying—33. Therefore, grain elevators are a significant source of particulate matter emissions and standards of performance have been developed for this source category.

Many commenters felt, however, that it was unreasonable to require small country elevators to comply with the proposed standards because of their remote location and small amount of emissions. This sentiment was reflected in the 1977 amendments to the Clean Air Act which exempted country elevators with a grain storage capacity of less than 88,100 m^3 (ca. 2.5 million U.S. bushels) from standards of performance. Consequently, the scope of the proposed standards has been narrowed and the promulgated standards apply only to new, modified, or reconstructed facilities within grain elevators with a permanent storage capacity in excess of 88,100 m^3.

A number of commenters also felt small flour mills should not be covered by standards of performance because they are also small sources of particulate matter emissions and handle less grain than some country elevators which were exempted from standards of performance by the 1977 amendments to the Clean Air Act. These processors are considered to be relatively small sources of particulate matter emissions that are best regulated by State and local regulations. Consequently, grain storage elevators at wheat flour mills, wet corn mills, dry corn mills (human consumption), rice mills, and soybean oil extraction plants with a storage capacity of less than 35,200 m^3 (ca. 1 million U.S. bushels) of grain are exempt from the promulgated standards.

With regard to the hazardous nature or toxicity of grain dust, the promulgated standards should not be interpreted to imply that grain dust is considered hazardous or toxic, but merely that the grain elevator industry is considered a significant source of particulate matter emissions. Studies indicate that, as a general class, particulate matter causes adverse health and welfare effects. In addition, some studies indicate that dust from grain elevators causes adverse health effects to elevator workers and that grain dust emissions are a factor contributing to an increased incidence of asthma attacks in the general population living in the vicinity of grain elevators.

EMISSION CONTROL TECHNOLOGY

A number of commenters were concerned with the reasonableness of the emission control technology which was used as the basis for the proposed standards limiting emissions from railcar unloading stations and grain dryers.

A number of commenters believed it was unreasonable to base the standards on a four-sided shed to capture emissions from railcar unloading stations at grain elevators which use unit trains. The data supporting the proposed standards were based on observations of visible emissions at a grain elevator which used this type of shed to control emissions from the unloading of railcars. This grain elevator, however, did not use unit trains. Based on information included in a number of comments, the lower rail rate for grain shipped by unit trains places a limit on the amount of time a grain elevator can hold the unit train. The additional time required to uncouple and recouple each car individually could cause a grain elevator subject to the proposed standards to exceed this time limit and thus lose the cost benefit gained by the use of unit trains. In light of this fact, the proposed visible emission limit for railcar unloading is considered unreasonable. The promulgated standards, therefore, are based upon the use of a two-sided shed for railcar unloading stations. This change in the control technology resulted in a change to the visible emission limit for railcar unloading stations and is discussed later.

A number of comments were received concerning the proposed standard for column dryers. The proposed standards would have permitted the maximum hole size in the perforated plates used in column dryers to be no larger than 2.1 mm (0.084 inch) in diameter for the dryer to automatically be in compliance with the standard. A few comments contained visible emission data taken by certified opacity observers which indicated that column dryers with perforated plates containing holes of 2.4 mm (0.094 inch) diameter could meet a 0-percent opacity emission limit. Other comments indicated that sorghum cannot be dried in column dryers with a hole size smaller than 2.4 mm (0.094 inch) diameter without plugging problems. In light of these data and information, the specification of 2.1 mm diameter holes is considered unreasonable and the promulgated standards apply only to column dryers containing perforated plates with hole sizes greater than 2.4 mm in diameter.

STRINGENCY OF THE STANDARDS

Many commenters questioned whether the standards for various affected facilities could be achieved even if the best system of emission reduction were installed, maintained, and properly operated. These commenters pointed out that a number of variables can affect the opacity of visible emissions during unloading, handling, and loading of grain and they questioned whether enough opacity observation had been taken to assure that the standards could be attained under all operating conditions. The variables mentioned most frequently were wind speed and type, dustiness, and moisture content of grain.

It is true that wind speed could have some effect on the opacity of visible emissions. A well-designed capture system should be able to compensate for this effect to a certain extent, although some dust may escape if wind speed is too high. Compliance with standards of performance, however, is determined only under conditions representative of normal operation, and judgment by State and Federal enforcement personnel will take wind conditions into account in enforcing the standards.

It is also true that the type, dustiness, and moisture content of grain affect the amount of particulate matter emissions generated during unloading, handling, and loading of grain. A well-designed capture system, however, should be designed to capture dust under adverse conditions and should, therefore, be able to compensate for these variables.

In developing the data base for the proposed standards, over 60 plant visits were made to grain terminal and storage elevators. Various grain unloading, handling, and loading operations were inspected under a wide variety of conditions. Consequently, the standards were not based on conjecture or surmise, but on observations of visible emissions by certified opacity observers at well-controlled existing grain elevators operating under routine conditions. Not all grain elevators were visited, however, and not all operations within grain elevators were inspected under all conditions. Thus, while the proposed standards were based upon a sufficiently broad data base to allow extrapolation of the data, particular attention was paid to those comments submitted during the public comment period which included visible emission data taken by certified observers from operations at grain elevators which were using the same emission control systems the proposed standards were based upon. Evaluation of these data indicates that the visible emission limit for truck unloading stations and railcar loading stations should be 5 percent opacity instead of 0 percent opacity which was proposed. The promulgated standards, therefore, limit visible emissions from these facilities to 5 percent opacity.

As discussed earlier, the emission control technology selected as the basis for the visible emissions standard for railcar unloading has been changed from a four-sided shed to a two-sided shed. Visible emission data included with the public comments indicate that emissions from a two-sided shed will not exceed 5 percent opacity. Consequently, the promulgated standards limit visible emissions from railcar unloading stations to 5 percent opacity.

A number of commenters also indicated that the opacity limit included in the proposed standards for barge loading was too stringent. One commenter indicated that the elevator operator had no control over when the "topping off" operation commenced because the ship captain and the stevedores decide when to start "topping off." Several State agencies commented that the standards should be at least 20 percent opacity. Based on these comments, the standards for barge and ship loading operations have been increased to 20 percent opacity during all loading operations. The comments indicate that this standard will still require use of the emission control technology upon which the proposed standards were based.

Data included with the public comments confirm that a visible emission limit of 0 percent opacity is appropriate for grain handling equipment, grain dryers, and emission control equipment. Consequently, the visible emission limits for these facilities have not been changed.

OPACITY

Many commenters misunderstood the concept of opacity and how it is used to measure visible emissions. Other commenters stated that opacity measurements were not accurate below 10 to 15 percent opacity and a standard below these levels was unenforceable.

Opacity is a measure of the degree to which particulate matter or other visible emissions reduce the transmission of light and obscure the view of an object in the background. Opacity is expressed on a scale of 0 to 100 percent with a totally opaque plume assigned a value of 100 percent opacity. The concept of opacity has been used in the field of air pollution control since the turn of the century. The concept has been upheld in courts throughout the country as a reasonable and effective means of measuring visible emissions.

Opacity for purposes of determining compliance with the standard is not determined with instruments but is determined by a qualified observer following a specific procedure. Studies have demonstrated that certified observers can accurately determine the opacity of visible emissions. To become certified, an individual must be trained and must pass an examination demonstrating his ability to accurately assign opacity levels to visible emissions. To remain certified, this training must be repeated every 6 months.

In accordance with method 9, the procedure followed in making opacity determinations requires that an observer be located in a position where he has a clear view of the emission source with the sun at his back. Instantaneous opacity observations are recorded every 15 seconds for 6 minutes (24 observations). These observations are recorded in 5 percent increments (i.e., 0, 5, 10, etc.). The arithmetic average of the 24 observations, rounded off to the nearest whole number (i.e., 0.4 would be rounded off to 0), is the value of the opacity used for determining compliance with visible emission standards. Consequently, a 0 percent opacity standard does not necessarily mean there are no visible emissions. It means either that visible emissions during a 6-minute period are not sufficient to cause a certified observer to record them as 5 percent opacity, or that the average of the twenty-four 15-second observations is calculated to be less than 0.5 percent. Consequently, although emissions released into the atmosphere from an emission source may be visible to a certified observer, the source may still be found in compliance with a 0 percent opacity standard.

Similarly, a 5-percent opacity standard permits visible emissions to exceed 5 percent opacity occasionally. If, for example, a certified observer recorded the following twenty-four 15-second observations over a 6-minute period: 7 observations at 0 percent opacity; 11 observations at 5 percent opacity; 3 observations at 10 percent opacity; and 3 observations at 15 percent opacity, the average opacity would be calculated as 5.4 percent. This value would be rounded off to 5 percent opacity and the source would be in compliance with a 5 percent opacity standard.

Some of the commenters felt the proposed standards were based only on one 6-minute reading of the opacity of visible emissions at various grain elevator facilities. None of the standards were based on a single 6-minute reading of opacity. Each of the standards were based on the highest opacity readings recorded over a period of time, such as 2 or 4 hours, at a number of grain elevators.

A number of commenters also felt the visible emission standards were too stringent in light of the maximum absolute error of 7.5 percent opacity associated with a single opacity observation. The methodology used to develop and enforce visible emission standards, however, takes into account this observer error. As discussed above, visible emission standards are based on observations recorded by certified observers at well-controlled existing facilities operating under normal conditions. When feasible, such observations are made under conditions which yield the highest opacity readings such as the use of a highly contrasting background. These readings then serve as the basis for establishing the standards. By relying on the highest observations, the standards inherently reflect the highest positive error introduced by the observers.

Observer error is also taken into account in enforcement of visible emission standards. A number of observations are normally made before an enforcement action is initiated. Statistically, as the number of observations increases, the error associated with these observations taken as a group decreases. Thus, while the absolute positive error associated with a single opacity observation may be 7.5 percent, the error associated with a number of opacity observations, taken to form the basis for an enforcement action, may be considerably less than 7.5 percent.

ECONOMIC IMPACT

Several commenters felt the estimated economic impact of the proposed standards was too low. Some commenters questioned the ventilation flow rate volumes used in developing these estimates. The air evacuation flow rates and equipment costs used in estimating the costs associated with the standards, however, were based on information obtained from grain elevator operators during visits to facilities which were being operated with visible emissions meeting the proposed standards. These air evacuation flow rates and equipment costs were also checked against equipment vendor estimates and found to be in reasonable agreement. These ventilation flow rates, therefore, are compatible with the opacity standards. Thus, the unit cost estimates developed for the proposed standards are considered reasonably accurate.

Many commenters felt that the total cost required to reduce emissions to the levels necessary to comply with the visible emission standards should be assigned to the standards. The relevant costs, however, are those incremental costs required to comply with these standards above the costs required to comply with existing State or local air pollution regulations. While it is true that some States have no regulations, other States have regulations as stringent as the promulgated standards. Consequently, an estimate of the costs required to comply with the typical or average State regu-

lation, which lies between these extremes, is subtracted from the total cost of complying with the standards to identify the cost impact directly associated with these standards.

Most State and local regulations, for example, require aspriation of truck dump pit grates and installation of cyclones to remove particulate matter from the aspirated air before release to the atmosphere. The promulgated standards would require the addition of a bifold door and the use of a fabric filter baghouse instead of a cyclone. The cost associated with the promulgated standards, therefore, is only the cost of the bifold doors and the difference in cost between a fabric filter baghouse and a cyclone.

In conclusion, the unit cost estimates developed for the proposed standards are essentially correct and generally reflect the costs associated with the promulgated standards. As a result, the economic impact of the promulgated standards on an individual grain elevator is considered to be about the same as that of the proposed standards. The maximum additional cost that would be imposed on most grain elevators subject to compliance with the promulgated standards will probably be less than a cent per bushel. The impact of these additional costs imposed on an individual grain elevator will be small.

Based on information contained in comments submitted by the National Grain and Feed Association, approximately 200 grain terminal elevators and grain storage elevators at grain processing plants will be covered by the standards over the next 5 years. Consequently, over this 5-year period the total incremental costs to control emissions at these grain elevators to comply with the promulgated standards, above the costs to control emissions at these elevators to comply with State or local air pollution control requirements, is $15 million in capital costs and $3 million in annualized costs in the 5th year. Based on this estimate of the national economic impact, the promulgated standards will have no significant effect on the supply and demand of grain or grain products, or on the growth of the domestic grain industry.

ENERGY IMPACT

A number of commenters believed that the energy impact associated with the proposed standards had been underestimated and that the true impact would be much greater. As pointed out above, the major reason for this disagreement is probably due to the fact that these commenters assigned the full impact of air pollution control to the proposed standards, whereas the impact associated with compliance with existing State and local air pollution control requirements should be subtracted. In the example discussed above concerning costs, the additonal energy requirements associated with the promulgated standards is simply the difference in energy required to operate a fabric filter baghouse compared to a cyclone.

For emission control equipment such as cyclones and fabric filter bag houses, energy consumption is directly proportional to the pressure drop across the equipment. It was assumed that the pressure drop across a cyclone required to comply with existing State and local requirements would be about 80 percent of that across a fabric filter baghouse required to comply with the promulgated standards. This is equivalent to an increase in energy consumption required to operate air pollution control equipment of about 25 percent. This represents an increase of less than 5 percent in the totl energy consumption of a grain elevator.

Assuming 200 grain elevators become subject to the promulgated standards over the next 5 years, this energy impact will increase national energy consumption by less than 1,600 m^3 (ca. 10,000 U.S. barrels) per year in 1982. This amounts to less than 2 percent of the capacity of a large marine oil tanker and is an insignificant increase in energy consumption.

MODIFICATION

Many commenters were under the mistaken impression that all existing grain elevators would have to comply with the proposed standards and that retrofit of air pollution control equipment on existing facilities within grain elevators would be required. This is not the case. The proposed standards would have applied only to new, modified, or reconstructed facilities within grain elevators. Similarly, the promulgated standards apply only to new, modified, or reconstructed facilities and not existing facilities.

Modified facilities are only subject to the standards if the modification results in increased emissions to the atmosphere from that facility. Furthermore, any alteration which is considered routine maintenance or repair is not considered a modification. Where an alteration is considered a modification, only those facilities which are modified have to comply with the standards, not the entire grain elevator. Consequently, the standards apply only to major alterations of individual facilities at existing grain elevators which result in increased emissions to the atmosphere, not to alterations which are considered routine maintenance and repair. Major alterations that do not result in increased emissions, such as alterations where existing air pollution control equipment is upgraded to maintain emissions at their previous level, are not considered modifications.

The following examples illustrate how the promulgated standards apply to a grain elevator under various circumstances. The proposed standards would have applied in the same way.

(1) If a completely new grain elevator were built, all affected facilities would be subject to the standards.

(2) If a truck unloading station at an existing grain elevator were modified by making a capital expenditure to increase unloading capacity and this resulted in increased emissions to the atmosphere in terms of pounds per hour, then only that affected facility (i. e., the modified truck unloading station) would be subject to the standards. The remaining facilities within the grain elevator would not be subject to the standards.

(3) if a grain elevator contained three grain dryers and one grain dryer were replaced with a new grain dryer, only the new grain dryer would be subject to the standards.

The initial assessment of the potential for modification of existing facilities concluded that few modifications would occur. The few modifications that were considered likely to take place would involve primarily the upgrading of existing country grain elevators into high throughput grain elevator terminals. A large number of commenters, however, indicated that they believed many modifications would occur and that many existing grain elevators would be required to comply with the standards.

To resolve this confusion and clarify the meaning of modification, a meeting was held with representatives of the grain elevator industry to identify various alterations to existing facilities that might be considered modifications. A list of alterations was developed which frequently occur within grain elevators, primarily to reduce labor costs or to increase grain handling capacity, although not necessarily annual grain throughput. The impact of considering four of these alterations as modifications, subject to compliance with the standards, was viewed as unreasonable. Consequently, they are exempted from consideration as modifications in the promulgated standards.

In particular, the four alterations within grain elevators which are specifically exempt from the promulgated standards are (1) The addition of gravity load-out spouts to existing grain storage or grain transfer bins; (2) the addition of electronic automatic grain weighing scales which increases hourly grain handling capacity; (3) the replacement of motors and drive trains driving existing grain handling equipment with larger motors and drive

trains which increases hourly grain handling capacity; and (4) the addition of grain storage capacity with no increase in hourly grain handling capacity.

If the first alteration were considered a modification, this could require installation of a load-out shed thereby requiring substantial reinforcement of the grain storage or grain transfer bin to support the weight of emission control equipment. In light of the relatively small expenditure usually required to install additional gravity load-out spouts to existing grain storage or transfer bins, and the relatively large expenditure that would be required to install a load-out shed or to reinforce the storage or transfer bin, consideration of this sort of alteration within an existing grain elevator as a modification was viewed as unreasonable.

Under the general modification regulation which applies to all standards of performance, alteration two, the addition of electronic automatic grain weighing scales, would be considered a change in the method of operation of the affected facility if it were to increase the hourly grain throughput. If this alteration were to increase emissions to the atmosphere and require a capital expenditure, the grain receiving or loading station whose method of operation had changed (i.e., increased grain throughput), would be considered a modified facility subject to the standards. Consideration of this type of alteration, which would result in only minor changes to a facility, is viewed as unreasonable in light of the relatively high expenditure this could require for existing grain elevators to comply with the standards.

Alterations three and four, replacement of existing motors and drives with larger motors and drives and addition of grain storage capacity with no increase in the hourly grain handling capacity, would probably not be considered modifications under the general modification regulation. Since it is quite evident that there was considerable confusion concerning modifications, however, alterations three and four, along with alterations one and two discussed above, are specifically exempt from consideration as modifications in the promulgated standards.

The modification provisions in 40 CFR 60.14(e) exempt certain physical or operational changes from being considered as modifications, even though an increase in emission rate occurs. Under 40 CFR 60.14(e)(2), if an increase in production rate of an existing facility can be accomplished without a capital expenditure on the stationary source containing that facility, the change is not considered a modification.

A capital expenditure is defined as any amount of money exceeding the product of the Internal Revenue Service (IRS) "annual asset guideline repair allowance percentage" times the basis of the facility, as defined by section 1012 of the Internal Revenue Code. In the case of grain elevators, the IRS has not listed an annual asset guideline repair allowance percentage. Following discussions with the IRS, the Department of Agriculture, and the grain elevator industry, the Agency determined that 6.5 percent is the appropriate percentage for the grain elevator industry. If the capital expenditures required to increase the production rate of an existing facility do not exceed the amount calculated under the IRS formula, the change in the facility is not considered a modification. If the expenditures exceed the calculated amount, the change in operation is considered a modification and the facility must comply with NSPS.

Often a physical or operational change to an existing facility to increase production rate will result in an increase in the production rate of another existing facility, even though it did not undergo a physical or operational change. For example, if new electronic weighing scales were added to a truck unloading station to increase grain receipts, the production rate and emission rate would increase at the unloading station. This could result in an increase in production rate and emission rate at other existing facilities (e.g., grain handling operations) even though physical or operational changes did not occur. Under the present wording of the regulation, expenditures made throughout a grain elevator to adjust for increased production rate would have to be considered in determining if a capital expenditure had been made on each facility whose operation is altered by the production increase. If the capital expenditure made on the truck unloading station were considered to be made on each existing facility which increased its production rate, it is possible that the alterations on each such facility would qualify as modifications. Each facility would, therefore, have to meet the applicable NSPS.

Such a result is inconsistent with the intent of the regulation. The Agency intended that only capital expenditures made for the changed facility are to be considered in determining if the change is a modification. Related expenditures on other existing facilities are not to be considered in the calculation. To clarify the regulation, the phrase "the stationary source containing" is being deleted. Because this is a clarification of intent and not a change in policy, the amendment is being promulgated as a final regulation without prior proposal.

PERFORMANCE TEST

Several commenters were concerned about the costs of conducting performance tests on fabric filter baghouses. These commenters stated that the costs involved might be a very substantial portion of the costs of the fabric filter baghouse itself, and several baghouses may be installed at a moderately sized grain elevator. The commenters suggested that a fabric filter baghouse should be assumed to be in compliance without a performance test if it were properly sized. In addition, the opacity standards could be used to demonstrate compliance.

It would not be wise to waive performance tests in all cases. Section 60.8(b) already provides that a performance test may be waived if "the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard." Since performance tests are heavily weighed in court proceedings, performance test requirements must be retained to insure effective enforcement.

SAFETY CONSIDERATIONS

In December 1977, and January 1978, several grain elevators exploded. Allegations were made by various individuals within the grain elevator industry contending that Federal air pollution control regulations were contributing to an increase in the risk of dust explosions at grain elevators by requiring that building doors and windows be closed and by concentrating grain dust in emission control systems. Investigation of these allegations indicates they are false.

There were no Federal regulations specifically limiting dust emissions from grain elevators which were in effect at the time of these grain elevator explosions. A number of State and local air pollution control agencies, however, have adopted regulations which limit particulate matter emissions from grain elevators. Many of these regulations were developed by States and included in their implementation plans for attaining and maintaining the NAAQS for particulate matter. Particulate matter, as a general class, can cause adverse health effects; and the NAAQS, which were promulgated on April 30, 1971, were established at levels necessary to protect the public health and welfare.

Although compliance with State or local air pollution control regulations, or the promulgated standards of performance, can be achieved in some instances by closing building doors and windows, this is not the objective of these regulations and is not an accept-

able means of compliance. The objective of State and local regulations and the promulgated standards of performance is that dust be captured at those points within grain elevators where it is generated through the use of effective hoods or enclosures with air aspiration, and removed from the grain elevator to an air pollution control device. This is the basis for the promulgated standards of performance. Compliance with air pollution control regulations and the promulgated standards of performance does not require that windows and doors in buildings be closed to prevent escape of dust and this practice may in fact be a major safety hazard.

Fabric filter baghouses have been used for many years to collect combustible dusts such as wheat flour. There have been extremely few incidences of dust explosions or fires caused by such emission control devices in the flour industry. In the grain elevator industry, no air pollution control device has been identified as the cause of a grain elevator explosion. Consequently, fabric filter baghouses, or emission control devices in general, which are properly designed, operated, and maintained will not contribute to an increased risk of dust explosions at grain elevators.

These conclusions were supported at a joint meeting between representatives of EPA; the Federal Grain Inspection Service (FGIS) of the Department of Agriculture; the Occupational Safety and Health Administration (OSHA); the grain elevator industry; and the fire insurance industry. Installation and use of properly designed, operated, and maintained air pollution control systems were found to be consistent with State and local air pollution regulations, OSHA regulations, and national fire codes. Chapter 6 of the National Fire Code for Grain Elevators and Bulk Grain Handling Facilities (NFPA No. 61-B), which was prepared by the National Fire Protection Association, for example, recommends that "dust shall be collected at all dust producing points within the processing facilities." The code then goes on to specially recommend that all elevator boots, automatic scales, scale hoppers, belt loaders, belt discharges, trippers, and discharge heads, and all machinery such as cleaners, scalpers, and similar devices be provided with enclosures or dust hoods and air aspiration.

Consequently, compliance with existing State or local air pollution regulations, or the promulgated standards of performance, will not increase the risk of dust explosions at grain elevators if the approach taken to meet these regulations is capture and control of dust at those points within an elevator where it is generated. If, however, the approach taken is merely to close doors, windows, and other openings to trap dust within the grain elevator, or the air pollution control equipment is allowed to deteriorate to the point where it is no longer effective in capturing dust as it is generated, then ambient concentrations of dust within the elevator will increase and the risk of explosion will also increase.

The House Subcommittee on Compensation, Health, and Safety is currently conducting oversight hearings to determine if something needs to be done to prevent these disastrous grain elevator explosions. The FGIS, EPA, and OSHA testified at these oversight hearings on January 24 and 25, 1978. The testimony indicated that dust should be captured and collected in emission control devices in order to reduce the incidence of dust explosions at grain elevators, protect the health of employees from such ailments as "farmer's lung," and prevent air pollution. Consequently, properly operated and maintained air pollution control equipment will not increase the risk of grain elevator explosions.

Miscellaneous

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements). State implementation plans (SIP's) approved or promulgated under section 110 of the act, on the other hand, must provide for the attainment and maintenance of national ambient air quality standards (NAAQS) designed to protect public health and welfare. For that purpose, SIP's must in some cases require greater emission reductions than those required by standards of performance for new sources. Section 173 of the act requires, among other things, that a new or modified source constructed in an area in violation of the NAAQS must reduce emissions to the level which reflects the "lowest achievable emission rate" for such category of source as defined in section 171(3). In no event can the emission rate exceed any applicable standard of performance.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area which falls under the prevention of significant deterioration of air quality provisions of the act (part C). These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology for all pollutants regulated under the act. The term "best available control technology" (BACT), as defined in section 169(3), means "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to sections 111 or 112 of this Act."

Standards of performance should not be viewed as the ultimate in achievable emission control and should not preclude the imposition of a more stringent emission standard, where appropriate. For example, while cost of achievement may be an important factor in determining standards of performance applicable to all areas of the country (clean as well as dirty), statutorily, costs do not play such a role in determining the "lowest achievable emission rate" for new or modified sources locating in areas violating statutorily mandated health and welfare standards. Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. This in no way should preclude its use in situations where cost is a lesser consideration, such as determination of the "lowest achievable emission rate."

In addition, States are free under section 116 of the act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

Economic Impact Assessment

An economic assessment has been prepared as required under section 317 of the Act."

Dated: July 26, 1978.

DOUGLAS M. COSTLE,
Administrator.

REFERENCES

1. "Standards Support and Environmental Impact Statement—Volume I: Proposed Standards of Performance for Grain Elevator Industry," U.S. Environmental Protection Agency—OAQPS, EPA-450/2-77-001a, Research Triangle Park, N.C., January 1977.
2. "Draft—For Review Only: Evaluation of Public Comments: Standards of Performance For Grain Elevators," U.S. Environmental Protection Agency—OAQPS, Research Triangle Park, N.C., August 1977.
3. "Standards Support and Environmental Impact Statement—Volume II: Promulgated Standards of Performance for Grain Elevator Industry," U.S. Environmental Protection Agency—OAQPS, EPA-450/2-77-001b, Research Triangle Park, N.C., April 1978.

Part 60 of chapter I, title 40 of the Code of Federal Regulations is amended as follows:

Subpart A—General Provisions

1. Section 60.2 is amended by revising paragraph (v). The revised paragaraph reads as follows:

§ 60.2 Definitions.

* * * * *

(v) "Particulate matter" means any finely divided solid or liquid material, other than uncombined water, as measured by the reference methods specified under each applicable subpart, or an equivalent or alternative method.

* * * * *

§ 60.14 [Amended]

2. Section 60.14 is amended by deleting the words "the stationary source containing" from paragraph (e)(2).

3. Part 60 is amended by adding subpart DD as follows:

Subpart DD—Standards of Performance for Grain Elevators

Sec.
60.300 Applicability and designation of affected facility.
60.301 Definitions.
60.302 Standard for particulate matter.
60.303 Test methods and procedures.
60.304 Modification.

AUTHORITY: Secs. 111 and 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

Subpart DD—Standards of Performance for Grain Elevators

§ 60.300 *Applicability and designation of* affected facility.

(a) The provisions of this subpart apply to each affected facility at any grain terminal elevator or any grain storage elevator, except as provided under § 60.304(b). The affected facilities are each truck unloading station, truck loading station, barge and ship unloading station, barge and ship loading station, railcar loading station, railcar unloading station, grain dryer, and all grain handling operations.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after (date of reinstatement of proposal) is subject to the requirements of this part.

§ 60.301 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the act and in subpart A of this part.

(a) "Grain" means corn, wheat, sorghum, rice, rye, oats, barley, and soybeans.

(b) "Grain elevator" means any plant or installation at which grain is unloaded, handled, cleaned, dried, stored, or loaded.

(c) "Grain terminal elevator" means any grain elevator which has a permanent storage capacity of more than 88,100 m^3 (ca. 2.5 million U.S. bushels), except those located at animal food manufacturers, pet food manufacturers, cereal manufacturers, breweries, and livestock feedlots.

(d) "Permanent storage capacity" means grain storage capacity which is inside a building, bin, or silo.

(e) "Railcar" means railroad hopper car or boxcar.

(f) "Grain storage elevator" means any grain elevator located at any wheat flour mill, wet corn mill, dry corn mill (human consumption), rice mill, or soybean oil extraction plant which has a permanent grain storage capacity of 35,200 m^3 (ca. 1 million bushels).

(g) "Process emission" means the particulate matter which is collected by a capture system.

(h) "Fugitive emission" means the particulate matter which is not collected by a capture system and is released directly into the atmosphere from an affected facility at a grain elevator.

(i) "Capture system" means the equipment such as sheds, hoods, ducts, fans, dampers, etc. used to collect particulate matter generated by an affected facility at a grain elevator.

(j) "Grain unloading station" means that portion of a grain elevator where the grain is transferred from a truck, railcar, barge, or ship to a receiving hopper.

(k) "Grain loading station" means that portion of a grain elevator where the grain is transferred from the elevator to a truck, railcar, barge, or ship.

(l) "Grain handling operations" include bucket elevators or legs (excluding legs used to unload barges or ships), scale hoppers and surge bins (garners), turn heads, scalpers, cleaners, trippers, and the headhouse and other such structures.

(m) "Column dryer" means any equipment used to reduce the moisture content of grain in which the grain flows from the top to the bottom in one or more continuous packed columns between two perforated metal sheets.

(n) "Rack dryer" means any equipment used to reduce the moisture content of grain in which the grain flows from the top to the bottom in a cascading flow around rows of baffles (racks).

(o) "Unloading leg" means a device which includes a bucket-type elevator which is used to remove grain from a barge or ship.

§ 60.302 Standard for particulate matter.

(a) On and after the 60th day of achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere any gases which exhibit greater than 0 percent opacity from any:

(1) Column dryer with column plate perforation exceeding 2.4 mm diameter (ca. 0.094 inch).

(2) Rack dryer in which exhaust gases pass through a screen filter coarser than 50 mesh.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility except a grain dryer any process emission which:

(1) Contains particulate matter in excess of 0.023 g/dscm (ca. 0.01 gr/dscf).

(2) Exhibits greater than 0 percent opacity.

(c) On and after the 60th day of achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere any fugitive emission from:

(1) Any individual truck unloading station, railcar unloading station, or railcar loading station, which exhibits greater than 5 percent opacity.

(2) Any grain handling operation which exhibits greater than 0 percent opacity.

(3) Any truck loading station which exhibits greater than 10 percent opacity.

(4) Any barge or ship loading station which exhibits greater than 20 percent opacity.

(d) The owner or operator of any barge or ship unloading station shall operate as follows:

(1) The unloading leg shall be enclosed from the top (including the receiving hopper) to the center line of the bottom pulley and ventilation to a control device shall be maintained on both sides of the leg and the grain receiving hopper.

(2) The total rate of air ventilated shall be at least 32.1 actual cubic meters per cubic meter of grain handling capacity (ca. 40 ft^3/bu).

(3) Rather than meet the requirements of subparagraphs (1) and (2), of this paragraph the owner or operator may use other methods of emission control if it is demonstrated to the Administrator's satisfaction that they would reduce emissions of particulate matter to the same level or less.

§ 60.303 Test methods and procedures.

(a) Reference methods in appendix A of this part, except as provided under § 60.8(b), shall be used to determine compliance with the standards prescribed under § 60.302 as follows:

(1) Method 5 or method 17 for concentration of particulate matter and associated moisture content;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate;

(4) Method 3 for gas analysis; and

(5) Method 9 for visible emissions.

(b) For method 5, the sampling probe and filter holder shall be operated without heaters. The sampling time for each run, using method 5 or method 17, shall be at least 60 minutes. The minimum sample volume shall be 1.7 dscm (ca. 60 dscf).

(Sec. 114, Clean Air Act, as amended (42 U.S.C. 7414).)

§ 60.304 Modifications.

(a) The factor 6.5 shall be used in place of "annual asset guidelines repair allowance percentage," to determine whether a capital expenditure as defined by § 60.2(bb) has been made to an existing facility.

(b) The following physical changes or changes in the method of operation shall not by themselves be considered a modification of any existing facility:

(1) The addition of gravity loadout spouts to existing grain storage or grain transfer bins.

(2) The installation of automatic grain weighing scales.

(3) Replacement of motor and drive units driving existing grain handling equipment.

(4) The installation of permanent storage capacity with no increase in hourly grain handling capacity.

[FR Doc. 78-21444 Filed 8-2-78; 8:45 am]

91

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 921-7]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Amendments to Kraft Pulp Mills Standard and Reference Method 16

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action amends the standards of performance for Kraft pulp mills by adding a provision for determining compliance of affected facilities which use a control system incorporating a process other than combustion. This amendment is necessary because the standards would place control systems other than combustion at a disadvantage. The intent of this amendment is to remove any preclusion of new and improved control systems. This action also amends Reference Method 16 to insure that the testing procedure is consistent with the promulgated standards.

EFFECTIVE DATE: August 7, 1978.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: Standards of performance for Kraft pulp mills were promulgated on February 23, 1978. On March 31, 1978, the National Council for Air and Stream Improvement (NCASI) requested two changes to these standards to prevent their interpretation in a manner which was inconsistent with their intent. The purpose of these amendments, therefore, is to clarify the intent of the standards.

Oxygen Correction Factors

In § 60.283(a)(1), the percent oxygen to which TRS emissions must be corrected was specified. The purpose of this specification was to provide a consistent basis for the determination of TRS emissions. Ten percent was selected because it reflected the observed oxygen concentrations on facilities controlled by the best system of emission reduction which was incineration. The NCASI pointed out, however, that the specification of a 10-percent oxygen level on sources which characteristically contain higher levels would effectively discourage the development of control technologies other than incineration.

The purpose of an emission standard is to reduce total emissions to the atmosphere. If an emission control technique should evolve which is capable of achieving the same mass rate of emissions from a given facility, use of that technique should be permitted. The standard, as written, could have inhibited the development of new technologies, if misinterpreted. Therefore, to remove this potential source of misinterpretation, § 60.283(a)(1)(v) has been added to the standard to provide for correction to untreated oxygen concentration in the case of brown stock washers, black liquor oxidation systems, or digester systems.

Reference Method 16

The second point of concern to the NCASI was the correction factor to be applied for sampling system losses contained in the post-test procedures (paragraph 10.1) of method 16. The specific concern was the specification that a test gas be introduced at the beginning of the probe to determine sample loss in the sampling train. The data base for the promulgated standard considered only TRS losses in the sampling train, not the probe or probe filter. Consequently, the post-test procedures are amended to require the determination of sampling train losses by introducing the test gas after the probe filter consistent with the data base supporting the promulgated standards.

Miscellaneous

The Administrator finds that good cause exists for omitting prior notice and public comment on these amendments and for making them immediately effective because they simply clarify the existing regulations and impose no additional substantive requirements.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for revisions determined by the Administrator to be substantial. Since the costs associated with the proposed amendments would have a negligible impact on consumer costs, the Administrator has determined that the proposed amendments are not substantial and do not require preparation of an economic impact assessment.

Dated: August 1, 1978.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of chapter I, title 40 of the Code of Federal Regulations is amended to read as follows:

1. In § 60.283, paragraph (a)(1) is amended to read as follows:

§ 60.283 Standard for total reduced sulfur (TRS).

* * * * *

(a) * * *

(1) * * *

(v) The gases from the digester system, brown stock washer system, condensate stripper system, or black liquor oxidation system are controlled by a means other than combustion. In this case, these systems shall not discharge any gases to the atmosphere which contain TRS in excess of 5 ppm by volume on a dry basis, corrected to the actual oxygen content of the untreated gas stream.

* * * * *

2. In appendix A, paragraph 10.1 of method 16 is amended to read as follows:

* * * * *

10 POST-TEST PROCEDURES

10.1 Sample line loss. A known concentration of hydrogen sulfide at the level of the applicable standard, ± 20 percent, must be introduced into the sampling system in sufficient quantities to insure that there is an excess of sample which must be vented to the atmosphere. The sample must be introduced immediately after the probe and filter and transported through the remainder of the sampling system to the measurement system in the normal manner The resulting measured concentration should be compared to the known value to determine the sampling system loss.

For sampling losses greater than 20 percent in a sample run, the sample run is not to be used when determining the arithmetic mean of the performance test. For sampling losses of 0-20 percent, the sample concentration must be corrected by dividing the sample concentration by the fraction of recovery. The fraction of recovery is equal to one minus the ratio of the measured concentration to the known concentration of hydrogen sulfide in the sample line loss procedure. The known gas sample may be generated using permeation tubes. Alternatively, cylinders of hydrogen sulfide mixed in air may be used provided they are traceable to permeation tubes. The optional pretest procedures provide a good guideline for determining if there are leaks in the sampling system.

* * * * *

(Sec. 111, 301(a)), Clean Air Act as amended (42 U.S.C. 7411, 7601(a)).)

[FR Doc. 78-21801 Filed 8 4-78, 8 45 am]

92

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY.

SUBCHAPTER C—AIR PROGRAMS

[FRL 987-8]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Delegation of Authority for State of Rhode Island

AGENCY: Environmental Protection Agency (EPA).

ACTION: Amendment.

SUMMARY: The delegation of authority to the State of Rhode Island for the standards of performance for new stationary sources (NSPS) was made on March 31, 1978. This amendment which adds the address of the Rhode Island Department of Environmenal Managment, reflects this delegation. A notice announcing this delegation is published today in the FEDERAL REGISTER.

EFFECTIVE DATE: October 16, 1978.

FOR FURTHER INFORMATION CONTACT:

John Courcier, Air Branch, EPA Region I, Room 2113, JFK Federal Building, Boston, Mass. 02203, 617-223-4448.

SUPPLEMENTARY INFORMATION: Under the delegation of authority for the standards of performance for new stationary sources (NSPS) to the State of Rhode Island on March 31, 1978, EPA is today amending 40 CFR 60.4, Address, to reflect this delegation. A notice announcing this delegation is published today elsewhere in this (43 part of the FEDERAL REGISTER. The amended § 60.4, which adds the address of the Rhode Island Department of Environmental Management to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on March 31, 1978, and it serves no purpose to delay the technical change of this addition of the State address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of section 111 of the Clean Air Act, as amended, 42 U.S.C. 7412.

Dated: September 18, 1978.

WILLIAM R. ADAMS, JR.,
Regional Administrator,
Region I.

Part 60 of chapter I, title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by adding subparagraph (OO) to read as follows:

§ 60.4 Address

* * * * *

(b) * * *

(OO) State of Rhode Island, Department of Environmental Management, 83 Park Street, Providence, R.I. 02908

[FR Doc. 78-29105 Filed 10-13-78; 9:49 am]

93

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 1012-2]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Appendix A—Reference Method 16

AGENCY: Environmental Protection Agency.

ACTION: Amendment.

SUMMARY: This action amends Reference Method 16 for determining total reduced sulfur emissions from stationary sources. The amendment corrects several typographical errors and improves the reference method by requiring the use of a scrubber to prevent potential interference from high SO_2 concentrations. These changes assure more accurate measurement of total reduced sulfur (TRS) emissions but do not substantially change the reference method.

SUPPLEMENTARY INFORMATION: On Februrary 23, 1978 (43 FR 7575), Appendix A—Reference Method 16 appeared with several typographical errors or omissions. Subsequent comments noted these and also suggested that the problem of high SO_2 concentrations could be corrected by using a scrubber to remove these high concentrations. This amendment corrects the errors of the original publication and slightly modifies Reference Method 16 by requiring the use of a scrubber to prevent potential interference from high SO_2 concentrations.

Reference Method 16 is the reference method specified for use in determining compliance with the promulgated standards of performance for kraft pulp mills. The data base used to develop the standards for kraft pulp mills has been examined and this additional requirement to use a scrubber to prevent potential interference from high SO_2 concentrations does not require any change to these standards of performance. The data used to develop these standards was not gathered from kraft pulp mills with high SO_2 concentrations; thus, the problem of SO_2 interference was not present in the data base. The use of a scrubber to prevent this potential interference in the future, therefore, is completely consistent with this data base and the promulgated standards.

The increase in the cost of determining compliance with the standards of performance for kraft pulp mills, as a result of this additional requirement to use a scrubber in Reference Method 16, is negligible. At most, this additional requirement could increase the cost of a performance test by about 50 dollars.

Because these corrections and additions to Reference Method 16 are minor in nature, impose no additional substantive requirements, or do not require a change in the promulgated standards of performance for kraft pulp mills, these amendments are promulgated directly.

EFFECTIVE DATE: January 12, 1979.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Director, Emission Standards and Engineering Division, (MD-13) Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number 919-541-5271.

Dated: January 2, 1979.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

APPENDIX A—REFERENCE METHODS

In Method 16 of Appendix A, Sections 3.4, 4.1, 4.3, 5, 5.5.2, 6, 8.3, 9.2, 10.3, 11.3, 12.1, 12.1.1.3, 12.1.3.1, 12.1.3.1.2, 12.1.3.2, 12.1.3.2.3, and 12.2 are amended as follows:

1. In subsection 3.4, at the end of the first paragraph, add: "In the example system, SO_2 is removed by a citrate buffer solution prior to GC injection. This scrubber will be used when SO_2 levels are high enough to prevent baseline separation from the reduced sulfur compounds."

2. In subsection 4.1, change "± 3 percent" to "± 5 percent."

3. In subsection 4.3, delete both sentences and replace with the following: "Losses through the sample transport system must be measured and a correction factor developed to adjust the calibration accuracy to 100 percent."

4. After Section 5 and before subsection 5.1.1 insert "5.1. Sampling."

5. In Section 5, add the following subsection: "5.3 SO_2 Scrubber. The SO_2 scrubber is a midget impinger packed with glass wool to eliminate entrained mist and charged with potassium citrate-citric acid buffer." Then increase all numbers from 5.3 up to and including 5.5.4 by 0.1, e.g., change 5.3 to 5.4, etc.

6. In subsection 5.5.2, the word "lowest" in the fourth sentence is replaced with "lower."

7. In Section 6, add the following subsection: "6.6 Citrate Buffer. Dissolve 300 grams of potassium citrate and 41 grams of anhydrous citric acid in 1 liter of deionized water. 284 grams of sodium citrate may be substituted for the potassium citrate."

8. In subsection 8.3, in the second sentence, after "Bypassing the dilution system," insert "but using the SO_2 scrubber," before finishing the sentence.

9. In subsection 9.2, replace sentence with the following: "Aliquots of diluted sample pass through the SO_2 scrubber, and then are injected into the GC/FPD analyzer for analysis."

10. In subsection 10.3, "paragraph" in the second sentence is corrected with "subsection."

11. In subsection 11.3 under B_{wo} definition, insert "Reference" before "Method 4."

12. In subsection 12.1.1.3 "(12.2.4 below)" is corrected to "(12.1.2.4 below)."

13. In subsection 12.1, add the following subsection: "12.1.3 SO_2 Scrubber. Midget impinger with 15 ml of potassium citrate buffer to absorb SO_2 in the sample." Then renumber existing section 12.1.3 and following subsections through and including 12.1.4.3 as 12.1.4 through 12.1.5.3.

14. The second subsection listed as "12.1.3.1" (before corrected in above amendment) should be "12.1.4.1.1."

15. In subsection 12.1.3.1 (amended above to 12.1.4.1) correct "GC/FPD-1 to "GC/FPD-I."

16. In subsection 12.1.3.1.2 (amended above to 12.1.4.1.2) omit "Packed as in 5.3.1." and put a period after "tubing."

17. In subsection 12.1.3.2 (amended above to 12.1.4.2) correct "GC/FPD-11" to "GC/FPD-II."

18. In subsection 12.1.3.2.3 (amended above to 12.1.4.2.3) the phrase "12.1.3.1.4. to 12.1.3.1.10" is corrected to read "12.1.4.1.5 to 12.1.4.1.10."

19. In subsection 12.2, add the following subsection: "12.2.7 Citrate Buffer. Dissolve 300 grams of potassium citrate and 41 grams of anhydrous citric acid in 1 liter of deionized water. 284 grams of sodium citrate may be substituted for the potassium citrate."

(Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601 (a))).

[FR Doc. 79-1047 Filed 1-11-79; 8:45 am]

94

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 1017-7]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Wood Residue-Fired Steam Generators

APPLICABILITY DETERMINATION

AGENCY: Environmental Protection Agency.

ACTION: Notice of Determination.

SUMMARY: This notice presents the results of a performance review of particulate matter control systems on wood residue-fired steam generators. On November 22, 1976 (41 FR 51397), EPA amended the standards of performance of new fossil-fuel-fired steam generators to allow the heat content of wood residue to be included with the heat content of fossil-fuel when determining compliance with the standards. EPA stated in the preamble that there were some questions about the feasibility of units burning a large portion of wood residue to achieve the particulate matter standard and announced that this would be reviewed. This review has been completed, and EPA concludes that the particulate matter standard can be achieved, therefore, no revision is necessary.

ADDRESSES: The document which presents the basis for this notice may be obtained from the Public Information Center (PM-215), U.S. Environmental Protection Agency, Washington, D.C. 20460 (specify "Wood Residue-Fired Steam Generator Particulate Matter Control Assessment," EPA-450/2-78-044.)

The document may be inspected and copied at the Public Information Reference Unit (EPA Library), Room 2922, 401 M Street, S.W., Washington, D.C.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Director, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5271.

SUPPLEMENTARY INFORMATION: On November 22, 1976, standards under 40 CFR Part 60, Subpart D for new fossil-fuel-fired steam generators were amended (41 FR 51397) to clarify that the standards apply to each fossil-fuel and wood residue-fired steam generating unit capable of firing fossil-fuel at a heat input of more than 73 megawatts (250 million Btu per hour). The primary objective of this amendment is to allow the heat input provided by wood residue to be used as a dilution agent in the calculations necessary to determine sulfur dioxide emissions. EPA recognized in the preamble of the amendment that questions remained concerning the ability of affected facilities which burn substantially more wood residue than fossil-fuel to comply with the standard for particulate matter. The preamble also stated that EPA was continuing to gather information on this question. The discussion that follows summarizes the results of EPA's examination of available information.

INTRODUCTION

Wood residue is a waste by-product of the pulp and paper industry which consists of bark, sawdust, slabs, chips, shavings, and mill trims. Disposal of this waste prior to the 1960's consisted mostly of incineration in Dutch ovens or open air tepees. Since then the advent of the spreader stroker boiler and the increasing costs of fossil-fuels has made wood residue an economical fuel to burn in large boilers for the generation of process steam.

There are several hundred steam generating boilers in the pulp and paper and allied forest product industry that use fuel which is partly or totally derived from wood residue. These boilers range in size from 6 megawatts (20 million Btu per hour) to 146 megawatts (500 million Btu per hour) and the total emissions from all boilers is estimated to be 225 tons of particulate matter per day after application of existing air pollution control devices.

Most existing wood residue-fired boilers subject to State emission standards are equipped with multitube-cyclone mechanical collectors. Manufacturers of the multitube collector have recognized that this type of control will not meet present new source standards and have been developing processes and devices to meet the new regulations. However, the use of these various systems on wood residue-fired boilers has not found widespread use to date, resulting in an information gap on expected performance of collector types other than conventional mechanical collectors.

In order to provide needed information in this area and to answer questions raised in the November 22, 1976 (41 FR 51397), amendment, a study was conducted on the most effective control systems in operation on wood residue-fired boilers. Also the amount and characteristics of the particulate emissions from wood residue-fired boilers was studied. The review that follows presents the results of that study.

PERFORMANCE REVIEW

The combustion of wood residue results in particulate emissions in the form of bark char or fly ash. Entrained with the char are varying amounts of sand and salt, the quantity depending on the method by which the original wood was logged and delivered. The fly ash particulates have a lower density and are larger in size than fly ash from coal-fired boilers. In general, the bark boiler exhaust gas will have a lower fly ash content than emissions from similar boilers burning physically cleaned coals or low-sulfur Western coals.

The bark fly ash, unlike most fly ash, is primarily unburned carbon. With collection and reinjection to the

boiler, greater carbon burnout can increase boiler efficiency from one to four percent. The reinjection of collected ash also significantly increases the dust loading since the sand is also recirculated with the fly ash. This increased dust loading can be accommodated by the use of sand separators or decantation type dust collectors. Collectors of this type in combination with more efficient units of air pollution control equipment constitute the systems currently in operation on existing plants that were found to operate with emissions less than the 43 nanograms per joule (0.10 pounds per million Btu) standard for particulate matter.

A survey of currently operated facilities that fire wood residue alone or in combination with fossil-fuel shows that most operate with mechanical collectors; some operate with low energy wet scrubbers, and a few facilities currently use higher energy venturi scrubbers (HEVS) or electrostatic precipitators (ESP). One facility reviewed is using a high temperature baghouse control system.

Currently, the use of multitube-cyclone mechanical collectors on hogged-fuel boilers provides the sole source of particulate removal for a majority of existing plants. The most commonly used system employs two multiclones in series allowing for the first collector to remove the bulk of the dust and a second collector with special high efficiency vanes for the removal of the finer particles. Collection efficiency for this arrangement ranges from 65 to 95 percent. This efficiency range is not sufficient to provide compliance with the particulate matter standard, but does provide a widely used first stage collection to which other control systems are added.

Of special note is one facility using a Swedish designed mechanical collector in series with conventional multiclone collectors. The Swedish collector is a small diameter multitube cyclone with a movable vane ring that imparts a spinning motion to the gases while at the same time maintaining a low pressure differential. This system is reducing emissions from the largest boiler found in the review to 107 nanograms per joule.

Electrostatic precipitators have been demonstrated to allow compliance with the particulate matter standard when coal is used as an auxiliary fuel. Available information indicates that this type of control provides high collection efficiencies on combination wood residue coal-fired boilers. One ESP collects particulate matter from a 50 percent bark, 50 percent coal combination fired boiler. An emission level of 13 nanograms per joule (.03 pounds per million Btu) was obtained using test methods recommended by the American Society of Mechanical Engineers.

The fabric filter (baghouse) particulate control system provides the highest collection efficency available, 99.9 percent. On one facility currently using a baghouse on a wood residue-fired boiler, the sodium chloride content of the ash being filtered is high enough (70 percent) that the possibility of fire is practically eliminated. Source test data collected with EPA Method 5 showed this system reduces the particulate emissions to 5 nanograms per joule (0.01 pounds per million Btu).

The application of fabric filters to control emissions from hogged fuel boilers has recently gained acceptance from several facilities of the paper and pulp industry, mainly due to the development of improved designs and operation procedures that reduce fire hazards. Several large sized boilers, firing salt and non-salt laden wood residue, are being equipped with fabric filter control systems this year and the performance of these installations will verify the effectiveness of fabric filtration.

Practically all of the facilities currently meeting the new source particulate matter standard are using wet scrubbers of the venturi or wet-impinger type. These units are usually connected in series with a mechanical collector. Three facilities reviewed which are using the wet-impingement type wet scrubber on large boilers burning 100 percent bark are producing particulate emissions well below the 43 nanograms per joule standard at operating pressure drops of 1.5 to 2 kPa (6 to 8 inches, H_2O). Five facilities using venturi type wet scrubbers on large boilers, two burning half oil and half bark and the other three burning 100 percent bark, are producing particulate emissions consistently below the standard at pressure drops of 2.5 to 5 kPa (10 to 20 inches, H_2O).

One facility has a large boiler burning 100 percent bark emitting a maximum of 5023 nanograms per joule of particulate matter into a multi-cyclone dust collector rated at an efficiency of 87 percent. The outlet loading from this mechanical collector is directed through two wet impingement-type scrubbers in parallel. With this arrangement of scrubbers, a collection efficiency of 97.7 percent is obtained at pressure drops of 2 kPa (8 inches, H_2O). Source test data collected with EPA Method 5 showed particulate matter emissions to be 15 nanograms per joule, well below the 43 nanograms per joule standard.

Another facility with a boiler of similar size and fuel was emitting a maximum of 4650 nanograms per joule into a multi-cyclone dust collector operating at a collection efficiency of 66 percent. The outlet loading from this collector is drawn into two wet-impingement scrubbers arranged in parallel. The operating pressure drop on these scrubbers was varied within the range of 1.6 to 2.0 kPa (6 to 8 inches, H_2O), resulting in a proportional decrease in discharged loadings of 25.8 to 18.5 nanograms per joule. Source test data collected on this source was obtained with the Montana Sampling Train.

Facilities using a venturi type wet scrubber were found to be able to meet the 43 nanogram per joule standard at higher pressure drops than the impingement type scrubber. One facility with a large boiler burning 100 percent bark had a multi-cyclone dust collector in series with a venturi wet scrubber operating at a pressure drop of 5 kPa (20 inches, H_2O). Source test data using EPA Method 5 showed this system consistently reduces emissions to an average outlet loading of 17.2 nanograms per joule of particulate matter. Another facility with a boiler burning 40 percent bark and 60 percent oil has a multi-cyclone and venturi scrubber system obtaining 25.8 nanograms per joule at a pressure drop of 2.5 kPa (10 inches, H_2O). The Florida Wet Train was used to obtain emission data on this source. A facility of similar design but burning 100 percent bark is obtaining the same emission control, 25.8 nanograms per joule, at a pressure drop of 3 kPa (12 inches, H_2O). Source test data collected on this source were obtained with the EPA Method 5.

This review has shown that the use of a wet scrubber, ESP, or a baghouse to control emissions from wood bark boilers will permit attainment of the particulate matter standard under 40 CFR Part 60. The control method currently used which has the widest application is the multitube cyclone collector in series with a venturi or wet-impingement type scrubber. Source test data have shown that facilities which burn substantially more wood residue than fossil-fuel have no difficulty in complying with the 43 nanogram per joule standard for particulate matter. Also the investigated facilities have been in operation successfully for a number of years without adverse economical problems. Therefore EPA has concluded from evaluation of the available information that no revision is required of the particulate matter standard for wood residue-fired boilers.

Dated: January 3, 1979.

DOUGLAS M. COSTLE,
Administrator.

[FR Doc. 79-1421 Filed 1-16-79; 8:45 am]

95

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

DELEGATION OF AUTHORITY TO STATE OF TEXAS

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This action amends Section 60.4, *Address*, to reflect the delegation of authority for the Standards of Performance for New Stationary Sources (NSPS) to the State of Texas.

EFFECTIVE DATE: February 7, 1979.

FOR FURTHER INFORMATION CONTACT:

James Veach, Enforcement Division, Region 6, Environmental Protection Agency, First International Building, 1201 Elm Street, Dallas, Texas 75270, telephone (214) 767-2760.

SUPPLEMENTARY INFORMATION: A notice announcing the delegation of authority is published elsewhere in the Notice Section in this issue of the FEDERAL REGISTER. These amendments provide that all reports and communications previously submitted to the Administrator, will now be sent to the Texas Air Control Board, 8520 Shoal Creek Boulevard, Austin, Texas 78758, instead of EPA's Region 6.

As this action is not one of substantive content, but is only an administrative change, public participation was judged unnecessary.

(Sections 111 and 301(a) of the Clean Air Act; Section 4(a) of Public Law 91-604, 84 Stat. 1683; Section 2 of Public Law 90-148, 81 Stat. 504 [42 U.S.C. 7411 and 7601(a)]).

Dated: November 15, 1978.

ADLENE HARRISON,
Regional Administrator,
Region 6.

Part 60 of Chapter 1, Title 40, Code of Federal Regulations, is amended as follows:

1. In § 60.4, paragraph (b) (SS) is amended as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(SS) State of Texas, Texas Air Control Board, 8520 Shoal Creek Boulevard, Austin, Texas 78758.

* * * * *

[FR Doc. 79-4223 Filed 2-6-79; 8:45 am]

96

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Petroleum Refineries—Clarifying Amendment

AGENCY: Environmental Protection Agency.

ACTION: Final Rule.

SUMMARY: These amendments clarify the definitions of "fuel gas" and "fuel gas combustion device" included in the existing standards of performance for petroleum refineries. These amendments will neither increase nor decrease the degree of emission control required by the existing standards. The objective of these amendments is to reduce confusion concerning the applicability of the sulfur dioxide standard to incinerator-waste heat boilers installed on fluid or Thermofor catalytic cracking unit catalyst regenerators and fluid coking unit coke burners.

EFFECTIVE DATE: March 12, 1979.

FOR FURTHER INFORMATION CONTACT:

Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5271.

SUPPLEMENTARY INFORMATION: On March 8, 1974 (39 FR 9315), standards of performance were promulgated limiting sulfur dioxide emissions from fuel gas combustion devices in petroleum refineries under 40 CFR Part 60, Subpart J. Fuel gas combustion devices are defined as any equipment, such as process heaters, boilers, or flares, used to combust fuel gas. Fuel gas is defined as any gas generated by a petroleum refinery process unit which is combusted. Fluid catalytic cracking unit and fluid coking unit incinerator-waste heat boilers, and facilities in which gases are combusted to produce sulfur or sulfuric acid are

exempted from consideration as fuel gas combustion devices.

Recently, the following two questions have been raised concerning the intent of exempting fluid catalytic cracking unit and fluid coking unit incinerator-waste heat boilers.

(1) Is it intended that Thermofor catalytic cracking unit incinerator waste-heat boilers be considered the same as fluid catalytic cracking unit incinerator-waste heat boilers?

(2) Is the exemption intended to apply to the incinerator-waste heat boiler as a whole including auxiliary fuel gas also combusted in this boiler?

The answer to the first question is yes. The answer to the second question is no.

The objective of the standards of performance is to reduce sulfur dioxide emissions from fuel gas combustion in petroleum refineries. The standards are based on amine treating of refinery fuel gas to remove hydrogen sulfide contained in these gases before they are combusted. The standards are not intended to apply to those gas streams generated by catalyst regeneration in fluid or Thermofor catalytic cracking units, or by coke burning in fluid coking units. These gas streams consist primarily of nitrogen, carbon monoxide, carbon dioxide, and water vapor, although small amounts of hydrogen sulfide may be present. Incinerator-waste heat boilers can be used to combust these gas streams as a means of reducing carbon monoxide emissions and/or generating steam. Any hydrogen sulfide present is converted to sulfur dioxide. It is not possible, however, to control sulfur dioxide emissions by removing whatever hydrogen sulfide may be present in these gas streams before they are combusted. The presence of carbon dioxide effectively precludes the use of amine treating, and since this technology is the basis for these standards, exemptions are included for fluid catalytic cracking units and fluid coking units.

Exemptions are not included for Thermofor catalytic cracking units because this technology is considered obsolete compared to fluid catalytic cracking. Thus, no new, modified, or reconstructed Thermofor catalytic cracking units are considered likely. The possibility that an incinerator-waste heat boiler might be added to an existing Thermofor catalytic cracking unit, however, was overlooked. To take this possibility into account, the definitions of "fuel gas" and "fuel gas combustion device" have been rewritten to exempt Thermofor catalytic cracking units from compliance in the same manner as fluid catalytic cracking units and fluid coking units.

As outlined above, the intent is to ensure that gas streams generated by catalyst regeneration or coke burning in catalytic cracking or fluid coking units are exempt from compliance with the standard limiting sulfur dioxide emissions from fuel gas combustion. This is accomplished under the standard as promulgated March 8, 1974, by exempting incinerator-waste heat boilers installed on these units from consideration as fuel gas combustion devices.

Incinerator-waste heat boilers installed to combust these gas streams require the firing of auxiliary refinery fuel gas. This is necessary to insure complete combustion and prevent "flame-out" which could lead to an explosion. By exempting the incinerator-waste heat boiler, however, this auxiliary refinery fuel gas stream is also exempted, which is not the intent of these exemptions. This auxiliary refinery fuel gas stream is normally drawn from the same refinery fuel gas system that supplies refinery fuel gas to other process heaters or boilers within the refinery. Amine treating can be used, and in most major refineries normally is used, to remove hydrogen sulfide from this auxiliary fuel gas stream as well as from all other refinery fuel gas streams.

To ensure that this auxiliary fuel gas stream fired in waste-heat boilers is not exempt, the definition of fuel gas combustion device is revised to eliminate the exemption for incinerator-waste heat boilers. In addition, the definition of fuel gas is revised to exempt those gas streams generated by catalyst regeneration in catalytic cracking units, and by coke burning in fluid coking units from consideration as refinery fuel gas. This will accomplish the original intent of exempting only those gas streams generated by catalyst regeneration or coke burning from compliance with the standard limiting sulfur dioxide emissions from fuel gas combustion.

MISCELLANEOUS: The Administrator finds that good cause exists for omitting prior notice and public comment on these amendments and for making them immediately effective because they simply clarify the existing regulations and impose no additional substantive requirements.

Dated: February 28, 1979.

DOUGLAS M. COSTLE,
Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. Section 60.101 is amended by revising paragraphs (d) and (g) as follows:

§ 60.101 Definitions.

* * * * *

(d) "Fuel gas" means natural gas or any gas generated by a petroleum refinery process unit which is combusted separately or in any combination. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking unit coke burners.

* * * * *

(g) "Fuel gas combustion device" means any equipment, such as process heaters, boilers, and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid.

* * * * *

(Sec. 111, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7601(a)))

[FR Doc. 79-7428 Filed 3-9-79; 8:45 am]

97

40 CFR Part 60

Standards of Performance for New Stationary Sources; Delegation of Authority to Washington Local Agency

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final Rulemaking.

SUMMARY: This rulemaking announces EPA's concurrence with the State of Washington Department of Ecology's (DOE) sub-delegation of the enforcement of the New Source Performance Standards (NSPS) program for asphalt batch plants to the Olympic Air Pollution Control Authority (OAPCA) and revises 40 CFR Part 60 accordingly. Concurrence was requested by the State on February 27, 1979.

EFFECTIVE DATE: April 19, 1979.

ADDRESS:

Environmental Protection Agency, Region X M/S 629, 1200 Sixth Avenue, Seattle, WA 98101.
State of Washington, Department of Ecology, Olympia, WA 98504.
Olympic Air Pollution Control Authority, 120 East State Avenue, Olympia, WA 98501.
Environmental Protection Agency, Public Information Reference Unit, Room 2922, 401 M Street SW., Washington, D.C. 20640.

FOR FURTHER INFORMATION CONTACT: Clark L. Gaulding, Chief, Air Programs Branch M/S 629, Environmental Protection Agency, 1200 Sixth Avenue, Seattle, WA 98101, Telephone No. (206) 442-1230 FTS 399-1230.

SUPPLEMENTARY INFORMATION: Pursuant to Section 111(c) of the Clean Air Act (42 USC 7411(c)), on February 27, 1979, the Washington State Department of Ecology requested that EPA concur with the State's sub-delegation of the NSPS program for asphalt batch plants to the Olympic Air Pollution Control Authority. After reviewing the State's request, the Regional Administrator has determined that the sub-delegation meets all requirements outlined in EPA's original February 28, 1975 delegation of authority, which was announced in the **Federal Register** on April 1, 1975 (40 FR 14632).

Therefore, on March 20, 1979, the Regional Administrator concurred in the sub-delegation of authority to the Olympic Air Pollution Control Authority with the understanding that all conditions placed on the original delegation to the State shall apply to the sub-delegation. By this rulemaking EPA is amending 40 CFR 60.4 (WW) to reflect the sub-delegation described above.

The amended § 60.4 provides that all reports, requests, applications and communications relating to asphalt batch plants within the jurisdiction of Olympic Air Pollution Control Authority (Clallam, Grays Harbor, Jefferson, Mason, Pacific and Thurston Counties) will now be sent to that Agency rather than the Department of Ecology. The amended section is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected.

This rulemaking is effective immediately, and is issued under the authority of Section 111(c) of the Clean Air Act, as amended. (42 U.S.C. 7411(c)).

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4, paragraph (b) is amended by revising subparagraph (WW) as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(WW) * * *

(vi) Olympic Air Pollution Control Authority, 120 East State Avenue, Olympia, WA 98501.

Dated: April 13, 1979.

Douglas M. Costle,
Administrator

[FRL 1202-6]

[FR Doc 79-12211 Filed 4-18-79; 8.45 am]

BILLING CODE 6560-01-M

9 8

40 CFR Part 60

[FRL 1240-7]

New Stationary Sources Performance Standards; Electric Utility Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: These standards of performance limit emissions of sulfur dioxide (SO_2), particulate matter, and nitrogen oxides (NO_x) from new, modified, and reconstructed electric utility steam generating units capable of combusting more than 73 megawatts (MW) heat input (250 million Btu/hour) of fossil fuel. A new reference method for determining continuous compliance with SO_2 and NO_x standards is also established. The Clean Air Act Amendments of 1977 require EPA to revise the current standards of performance for fossil-fuel-fired stationary sources. The intended effect of this regulation is to require new, modified, and reconstructed electric utility steam generating units to use the best demonstrated technological system of continuous emission reduction and to satisfy the requirements of the Clean Air Act Amendments of 1977.

DATES: The effective date of this regulation is June 11, 1979.

ADDRESSES: A Background Information Document (BID; EPA 450/3-79-021) has been prepared for the final standard. Copies of the BID may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, N.C. 27711, telephone 919-541-2777. In addition, a copy is available for inspection in the Office of Public Affairs in each Regional Office, and in EPA's Central Docket Section in Washington, D.C. The BID contains (1) a summary of all the public comments made on the proposed regulation; (2) a summary of the data EPA has obtained since proposal on SO_2, particulate matter, and NO_x emissions; and (3) the final Environmental Impact Statement which summarizes the impacts of the regulation.

Docket No. OAQPS-78-1 containing all supporting information used by EPA in developing the standards is available for public inspection and copying between 8 a.m. and 4 p.m., ge a11jn0.005Monday through Friday, at EPA's Central Docket Section, room 2903B, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460.

The docket is an organized and complete file of all the information submitted to or otherwise considered by the Administrator in the development of this rulemaking. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process. Along with the statement of basis and purpose of the promulgated rule and EPA responses to significant comments, the contents of the docket will serve as the record in case of judicial review [section 107(d)(a)].

FOR FURTHER INFORMATION CONTACT: Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: This preamble contains a detailed discussion of this rulemaking under the following headings: SUMMARY OF STANDARDS, RATIONALE, BACKGROUND, APPLICABILITY, COMMENTS ON PROPOSAL, REGULATORY ANALYSIS, PERFORMANCE TESTING, MISCELLANEOUS.

Summary of Standards

Applicability

The standards apply to electric utility steam generating units capable of firing more than 73 MW (250 million Btu/hour) heat input of fossil fuel, for which construction is commenced after September 18, 1978. Industrial cogeneration facilities that sell less than 25 MW of electricity, or less than one-third of their potential electrical output capacity, are not covered. For electric utility combined cycle gas turbines, applicability of the standards is determined on the basis of the fossil-fuel fired to the steam generator exclusive of the heat input and electrical power contribution of the gas turbine.

SO_2 Standards

The SO_2 standards are as follows:

(1) Solid and solid-derived fuels (except solid solvent refined coal): SO_2 emissions to the atmosphere are limited to 520 ng/J (1.20 lb/million Btu) heat input, and a 90 percent reduction in potential SO_2 emissions is required at all times except when emissions to the atmosphere are less than 260 ng/J (0.60 lb/million Btu) heat input. When SO_2 emissions are less than 260 mg/J (0.60 lb/million Btu) heat input, a 70 percent reduction in potential emissions is required. Compliance with the emission limit and percent reduction requirements is determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average. The percent reduction is computed on the basis of overall SO_2 removed by all types of SO_2 and sulfur removal technology, including flue gas desulfurization (FGD) systems and fuel pretreatment systems (such as coal cleaning, coal gasification, and coal liquefaction). Sulfur removed by a coal pulverizer or in bottom ash and fly ash may be included in the computation.

(2) Gaseous and liquid fuels not derived from solid fuels: SO_2 emissions into the atmosphere are limited to 340 ng/J (0.80 lb/million Btu) heat input, and a 90 percent reduction in potential SO_2 emissions is required. The percent reduction requirement does not apply if SO_2 emissions into the atmosphere are less than 86 ng/J (0.20 lb/million Btu) heat input. Compliance with the SO_2 emission limitation and percent reduction is determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average.

(3) Anthracite coal: Electric utility steam generating units firing anthracite coal alone are exempt from the percentage reduction requirement of the SO_2 standard but are subject to the 520 ng/J (1.20 lb/million Btu) heat input emission limit on a 30-day rolling average, and all other provisions of the regulations including the particulate matter and NO_x standards.

(4) Noncontinental areas: Electric utility steam generating units located in noncontinental areas (State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Mariana Islands) are exempt from the percentage reduction requirement of the SO_2 standard but are subject to the applicable SO_2 emission limitation and all other provisions of the regulations including the particulate matter and NO_x standards.

(5) Resource recovery facilities: Resource recovery facilities that fire less than 25 percent fossil-fuel on a quarterly (90-day) heat input basis are not subject to the percentage reduction requirements but are subject to the 520 ng/J (1.20 lb/million Btu) heat input emission limit. Compliance with the emission limit is determined on a continuous basis using continuous monitoring to obtain a 30-day rolling average. In addition, such facilities must monitor and report their heat input by fuel type.

(6) Solid solvent refined coal: Electric utility steam generating units firing solid solvent refined coal (SRC I) are subject

to the 520 ng/J (1.20 lb/million Btu) heat input emission limit (30-day rolling average) and all requirements under the NO_x and particulate matter standards. Compliance with the emission limit is determined on a continuous basis using a continuous monitor to obtain a 30-day rolling average. The percentage reduction requirement for SRC I, which is to be obtained at the refining facility itself, is 85 percent reduction in potential SO_2 emissions on a 24-hour (daily) averaging basis. Compliance is to be determined by Method 19. Initial full scale demonstration facilities may be granted a commercial demonstration permit establishing a requirement of 80 percent reduction in potential emissions on a 24-hour (daily) basis.

Particulate Matter Standards

The particulate matter standard limits emissions to 13 ng/J (0.03 lb/million Btu) heat input. The opacity standard limits the opacity of emission to 20 percent (6-minute average). The standards are based on the performance of a well-designed and operated baghouse or electostatic precipitator (ESP).

NO_x Standards

The NO_x standards are based on combustion modification and vary according to the fuel type. The standards are:

(1) 86 ng/J (0.20 lb/million Btu) heat input from the combustion of any gaseous fuel, except gaseous fuel derived from coal;

(2) 130 ng/J (0.30 lb/million Btu) heat input from the combustion of any liquid fuel, except shale oil and liquid fuel derived from coal;

(3) 210 ng/J (0.50 lb/million Btu) heat input from the combustion of subbituminous coal, shale oil, or any solid, liquid, or gaseous fuel derived from coal;

(4) 340 ng/J (0.80 lb/million Btu) heat input from the combustion in a slag tap furnace of any fuel containing more than 25 percent, by weight, lignite which has been mined in North Dakota, South Dakota, or Montana;

(5) Combustion of a fuel containing more than 25 percent, by weight, coal refuse is exempt from the NO_x standards and monitoring requirements; and

(6) 260 ng/J (0.60 lb/million Btu) heat input from the combustion of any solid fuel not specified under (3), (4), or (5).

Continuous compliance with the NO_x standards is required, based on a 30-day rolling average. Also, percent reductions in uncontrolled NO_x emission levels are required. The percent reductions are not controlling, however, and compliance with the NO_x emission limits will assure compliance with the percent reduction requirements.

Emerging Technologies

The standards include provisions which allow the Administrator to grant commercial demonstration permits to allow less stringent requirements for the initial full-scale demonstration plants of certain technologies. The standards include the following provisions:

(1) Facilities using SRC I would be subject to an emission limitation of 520 ng/J (1.20 lb/million Btu) heat input, based on a 30-day rolling average, and an emission reduction requirement of 85 percent, based on a 24-hour average. However, the percentage reduction allowed under a commercial demonstration permit for the initial full-scale demonstration plants, using SRC I would be 80 percent (based on a 24-hour average). The plant producing the SRC I would monitor to insure that the required percentage reduction (24-hour average) is achieved and the power plant using the SRC I would monitor to insure that the 520 ng/J heat input limit (30-day rolling average) is achieved.

(2) Facilities using fluidized bed combustion (FBC) or coal liquefaction would be subject to the emission limitation and percentage reduction requirement of the SO_2 standard and to the particulate matter and NO_x standards. However, the reduction in potential SO_2 emissions allowed under a commercial demonstration permit for the initial full-scale demonstration plants using FBC would be 85 percent (based on a 30-day rolling average). The NO_x emission limitation allowed under a commercial demonstration permit for the initial full-scale demonstration plants using coal liquefaction would be 300 ng/J (0.70 lb/million Btu) heat input, based on a 30-day rolling average.

(3) No more than 15,000 MW equivalent electrical capacity would be allotted for the purpose of commercial demonstration permits. The capacity will be allocated as follows:

Technology	Pollutant	Equivalent electrical capacity MW
Solid solvent-refined coal	SO_2	5,000–10,000
Fluidized bed combustion (atmospheric)	SO_2	400–3,000
Fluidized bed combustion (pressurized)	SO_2	200–1,200
Coal liquefaction	NO_x	750–10,000

Compliance Provisions

Continuous compliance with the SO_2 and NO_x standards is required and is to be determined with continuous emission monitors. Reference methods or other approved procedures must be used to supplement the emission data when the continuous emission monitors malfunction, to provide emissions data for at least 18 hours of each day for at least 22 days out of any 30 successive days of boiler operation.

A malfunctioning FGD system may be bypassed under emergency conditions. Compliance with the particulate standard is determined through performance tests. Continuous monitors are required to measure and record the opacity of emissions. This data is to be used to identify excess emissions to insure that the particulate matter control system is being properly operated and maintained.

Rationale

SO_2 Standards

Under section 111(a) of the Act, a standard of performance for a fossil-fuel-fired stationary source must reflect the degree of emission limitation and percentage reduction achievable through the application of the best technological system of continuous emission reduction taking into consideration cost and any nonair quality health and environmental impacts and energy requirements. In addition, credit may be given for any cleaning of the fuel, or reduction in pollutant characteristics of the fuel, after mining and prior to combustion.

In the 1977 amendments to the Clean Air Act, Congress was severely critical of the current standard of performance for power plants, and especially of the fact that it could be met by the use of untreated low-sulfur coal. The House, in particular, felt that the current standard failed to meet six of the purposes of section 111. The six purposes are (H. Rept. at 184–186):

1. The standards must not give a competitive advantage to one State over another in attracting industry.

2. The standards must maximize the potential for long-term economic growth by reducing emissions as much as practicable. This would increase the amount of industrial growth possible within the limits set by the air quality standards.

3. The standards must to the extent practical force the installation of all the control technology that will ever be necessary on new plants at the time of construction when it is cheaper to install, thereby minimizing the need for retrofit in the future when air quality standards begin to set limits to growth.

4 and 5. The standards to the extent practical must force new sources to burn high-sulfur fuel thus freeing low-sulfur fuel for use in existing sources where it

is harder to control emissions and where low-sulfur fuel is needed for compliance. This will (1) allow old sources to operate longer and (2) expand environmentally acceptable energy supplies.

6. The standards should be stringent in order to force the development of improved technology.

To deal with these perceived deficiences, the House initiated revisions to section 111 as follows:

1. New source performance standards must be based on the "best technological" control system that has been "adequately demonstrated," taking cost and other factors such as energy into account. The insertion of the word "technological" precludes a new source performance standard based solely on the use of low-sulfur fuels.

2. New source performance standards for fossil-fuel-fired sources (e.g., power plants) must require a "percentage reduction" in emissions, compared to the emissions that would result from burning untreated fuels.

The Conference Committee generally followed the House bill. As a result, the 1977 amendments substantially changed the criteria for regulating new power plants by requiring the application of technological methods of control to minimize SO_2 emissions and to maximize the use of locally available coals. Under the statute, these goals are to be achieved through revision of the standards of performance for new fossil-fuel-fired stationary sources to specify (1) an emission limitation and (2) a percentage reduction requirement. According to legislative history accompanying the amendments, the percentage reduction requirement should be applied uniformly on a nationwide basis, unless the Administrator finds that varying requirements applied to fuels of differing characteristics will not undermine the objectives of the house bill and other Act provisions.

The principal issue throughout this rulemaking has been whether a plant burning low-sulfur coal should be required to achieve the same percentage reduction in potential SO_2 emissions as those burning higher sulfur coal. The public comments on the proposed rules and subsequent analyses performed by the Office of Air, Noise and Radiation of EPA served to bring into focus several other issues as well.

These issues included performance capabilities of SO_2 control technology, the averaging period for determining compliance, and the potential adverse impact of the emission ceiling on high-sulfur coal reserves.

Prior to framing the final SO_2 standards, the EPA staff carried out extensive analyses of a range of alternative SO_2 standards using an econometric model of the utility sector. As part of this effort, a joint working group comprised of representatives from EPA, the Department of Energy, the Council of Economic Advisors, the Council on Wage and Price Stability, and others reviewed the underlying assumptions used in the model. The results of these analyses served to identify environmental, economic, and energy impacts associated with each of the alternatives considered at the national and regional levels. In addition, supplemental analyses were performed to assess impacts of alternative emission ceilings on specific coal reserves, to verify performance characteristics of alternative SO_2 scrubbing technologies, and to assess the sulfur reduction potential of coal preparation techniques.

Based on the public record and additional analyses performed, the Administrator concluded that a 90 percent reduction in potential SO_2 emissions (30-day rolling average) has been adequately demonstrated for high-sulfur coals. This level can be achieved at the individual plant level even under the most demanding conditions through the application of flue gas desulfurization (FGD) systems together with sulfur reductions achieved by currently practiced coal preparation techniques. Reductions achieved in the fly ash and bottom ash are also applicable. In reaching this finding, the Administrator considered the performance of currently operating FGD systems (scrubbers) and found that performance could be upgraded to achieve the recommended level with better design, maintenance, and operating practices. A more stringent requirement based on the levels of scrubber performance specified for lower sulfur coals in a number of prevention of significant deterioration permits was not adopted since experience with scrubbers operating with such performance levels on high-sulfur coals is limited. In selecting a 30-day rolling average as the basis for determining compliance, the Administrator took into consideration effects of coal sulfur variability on scrubber performance as well as potential adverse impacts that a shorter averaging period may have on the ability of small plants to comply.

With respect to lower sulfur coals, the EPA staff examined whether a uniform or variable application of the percent reduction requirement would best satisfy the statutory requirements of section 111 of the Act and the supporting legislative history. The Conference Report for the Clean Air Act Amendments of 1977 says in the pertinent part:

> In establishing a national percent reduction for new fossil fuel-fired sources, the conferees agreed that the Administrator may, in his discretion, set a range of pollutant reduction that reflects varying fuel characteristics. Any departure from the uniform national percentage reduction requirement, however, must be accompanied by a finding that such a departure does not undermine the basic purposes of the House provision and other provisions of the act, such as maximizing the use of locally available fuels.

In the face of such language, it is clear that Congress established a presumption in favor of a uniform application of the percentage reduction requirement and that any departure would require careful analysis of objectives set forth in the House bill and the Conference Report.

This question was made more complex by the emergence of dry SO_2 control systems. As a result of public comments on the discussion of dry SO_2 control technology in the proposal, the EPA staff examined the potential of this technology in greater detail. It was found that the development of dry SO_2 controls has progressed rapidly during the past 12 months. Three full scale systems are being installed on utility boilers with scheduled start up in the 1981–1982 period. These already contracted systems have design efficiencies ranging from 50 to 85 percent SO_2 removal, long term average. In addition, it was determined that bids are currently being sought for five more dry control systems (70 to 90 percent reduction range) for utility applications.

Activity in the dry SO_2 control field is being stimulated by several factors. First, dry control systems are less complex than wet technology. These simplified designs offer the prospect of greater reliability at substantially lower costs than their wet counterparts. Second, dry systems use less water than wet scrubbers, which is an important consideration in the Western part of the United States. Third, the amount of energy required to operate dry systems is less than that required for wet systems. Finally, the resulting waste product is more easily disposed of than wet sludge.

The applicability of dry control technology, however, appears limited to low-sulfur coals. At coal sulfur contents greater than about 1290 ng/J (3 pounds SO_2/million Btu), or about 1.5 percent sulfur coal, available data indicate that

it probably will be more economical to employ a wet scrubber than a dry control system.

Faced with these findings, the Administrator had to determine what effect the structure of the final regulation would have on the continuing development and application of this technology. A thorough engineering review of the available data indicated that a requirement of 90 percent reduction in potential SO_2 emissions would be likely to constrain the full development of this technology by limiting its potential applicability to high alkaline content, low-sulfur coals. For non-alkaline, low-sulfur coals, the certainty of economically achieving a 90 percent reduction level is markedly reduced. In the face of this finding, it would be unlikely that the technology would be vigorously pursued for these low alkaline fuels which comprise approximately one half of the Nation's low-sulfur coal reserves. In view of this, the Administrator sought a percentage reduction requirement that would provide an opportunity for dry SO_2 technology to be developed for all low-sulfur coal reserves and yet would be sufficiently stringent to assure that the technology was developed to its fullest potential. The Administrator concluded that a variable control approach with a minimum requirement of 70 percent reduction potential in SO_2 emissions (30-day rolling average) for low-sulfur coals would fulfill this objective. This will be discussed in more detail later in the preamble. Less stringent, sliding scale requirements such as those offered by the utility industry and the Department of Energy were rejected since they would have higher associated emissions, would not be significantly less costly, and would not serve to encourage development of this technology.

In addition to promoting the development of dry SO_2 systems, a variable approach offers several other advantages often cited by the utility industry. For example, if a source chose to employ wet technology, a 70 percent reduction requirement serves to substantially reduce the energy impact of operating wet scrubbers in low-sulfur coals. At this level of wet scrubber control, a portion of the untested flue gas could be used for plume reheat so as to increase plume buoyancy, thus reducing if not eliminating the need to expend energy for flue gas reheat. Further, by establishing a range of percent reductions, a variable approach would allow a source some flexibility particularly when selecting intermediate sulfur content coals. Finally, under a variable approach, a source could move to a lower sulfur content coal to achieve compliance if its control equipment failed to meet design expectations. While these points alone would not be sufficient to warrant adoption of a variable standard, they do serve to supplement the benefits associated with permitting the use of dry technology.

Regarding the maximum emission limitation, the Administrator had to determine a level that was appropriate when a 90 percent reduction in potential emissions was applied to high-sulfur coals. Toward this end, detailed assessments of the potential impacts of a wide range of emission limitations on high-sulfur coal reserves were performed. The results revealed that a significant portion (up to 30 percent) of the high-sulfur coal reserves in the East, Midwest and portions of the Northern Appalachia coal regions would require more than a 90 percent reduction if the emission limitation were established below 520 ng/J (1.2 lb/million Btu) heat input on a 30-day rolling average basis. Although higher levels of control are technically feasible, conservatism in utility perceptions of scrubber performance could create a significant disincentive against the use of these coals and disrupt the coal markets in these regions. Accordingly, the Administrator concluded the emission limitation should be maintained at 520 ng/J (1.2 lb/million Btu) heat input on a 30-day rolling average basis. A more stringent emission limit would be counter to one of the purposes of the 1977 Amendments, that is, encouraging the use of higher sulfur coals.

Having determined an appropriate emission limitation and that a variable percent reduction requirement should be established, the Administrator directed his attention to specifying the final form of the standard. In doing so, he sought to achieve the best balance in control requirements. This was accomplished by specifying a 520 ng/J (1.2 lb/million Btu) heat input emission limitation with a 90 percent reduction in potential SO_2 emissions except when emissions to the atmosphere were reduced below 260 ng/J (0.6 lb/million Btu) heat input (30-day rolling average), when only a 70 percent reduction in potential SO_2 emissions would apply. Compliance with each of the requirements would be determined on the basis of a 30-day rolling average. Under this approach, plants firing high-sulfur coals would be required to achieve a 90 percent reduction in potential emissions in order to comply with the emission limitation. Those using intermediate- or low-sulfur content coals would be permitted to achieve between 70 and 90 percent reduction, provided their emissions were less than 260 ng/J (0.6 lb/million Btu). The 260 ng/J (0.6 lb/million Btu) level was selected to provide for a smooth transition of the percentage reduction requirement from high- to low-sulfur coals. Other transition points were examined but not adopted since they tended to place certain types of coal at a disadvantage.

By fashioning the SO_2 standard in this manner, the Administrator believes he has satisfied both the statutory language of section 111 and the pertinent part of the Conference Report. The standard reflects a balance in environmental, economic, and energy considerations by being sufficiently stringent to bring about substantial reductions in SO_2 emissions (3 million tons in 1995) yet does so at reasonable costs without significant energy penalties. When compared to a uniform 90 percent reduction, the standard achieves the same emission reductions at the national level. More importantly, by providing an opportunity for full development of dry SO_2 technology the standard offers potential for further emission reductions (100 to 200 thousand tons per year), cost savings (over $1 billion per year), and a reduction in oil consumption (200 thousand barrels per day) when compared to a uniform standard. The standard through its balance and recognition of varying coal characteristics, serves to expand environmentally acceptable energy supplies without conveying a competitive advantage to any one coal producing region. The maintenance of the emission limitation at 520 ng/J (1.2 lb SO_2/million Btu) will serve to encourage the use of locally available high-sulfur coals. By providing for a range of percent reductions, the standard offers flexibility in regard to burning of intermediate sulfur content coals. By placing a minimum requirement of 70 percent on low-sulfur coals, the final rule encourages the full development and application of dry SO_2 control systems on a range of coals. At the same time, the minimum requirement is sufficiently stringent to reduce the amount of low-sulfur coal that moves eastward when compared to the current standard. Admittedly, a uniform 90 percent requirement would reduce such movements further, but in the Administrator's opinion, such gains would be of marginal value when compared to expected increases in high-sulfur coal production. By achieving a balanced coal demand within the utility sector and by promoting the development of less expensive SO_2 control technology, the final standard

will expand environmentally acceptable energy supplies to existing power plants and industrial sources.

By substantially reducing SO_2 emissions, the standard will enhance the potential for long term economic growth at both the national and regional levels. While more restrictive requirements may have resulted in marginal air quality improvements locally, their higher costs may well have served to retard rather than promote air quality improvement nationally by delaying the retirement of older, poorly controlled plants.

The standard must also be viewed within the broad context of the Clean Air Act Amendments of 1977. It serves as a minimum requirement for both prevention of significant deterioration and non-attainment considerations. When warranted by local conditions, ample authority exists to impose more restrictive requirements through the case-by-case new source review process. When exercised in conjunction with the standard, these authorities will assure that our pristine areas and national parks are adequately protected. Similarly, in those areas where the attainment and maintenance of the ambient air quality standard is threatened, more restrictive requirements will be imposed.

The standard limits SO_2 emissions from facilities firing gaseous or liquid fuels to 340 ng/J (0.80 lb/million Btu) heat input and requires 90 percent reduction in potential emissions on a 30-day rolling average basis. The percent reduction does not apply when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input on a 30-day rolling average basis. This reflects a change to the proposed standards in that the time for compliance is changed from the proposed 24-hour basis to a 30-day rolling average. This change is necessary to make the compliance times consistent for all fuels. Enforcement of the standards would be complicated by different averaging times, particularly when more than one fuel is used.

Particulate Matter Standard

The standard for particulate matter limits the emissions to 13 ng/J (0.03 lb/million Btu) heat input and requires a 99 percent reduction in uncontrolled emissions for solid fuels and a 70 percent reduction for liquid fuels. No particulate matter control is necessary for units firing gaseous fuels alone, and a percent reduction is not required. The percent reduction requirements for solid and liquid fuels are not controlling, and compliance with the particulate matter emission limit will assure compliance with the percent reduction requirements.

A 20 percent (6-minute average) opacity limit is included in this standard. The opacity limit is included to insure proper operation and maintenance of the emission control system. If an affected facility were to comply with all applicable standards except opacity, the owner or operator may request that the Administrator, under 40 CFR 60.11(e), establish a source-specific opacity limit for that affected facility.

The standard is based on the performance of a well-designed, operated and maintained electrostatic precipitator (ESP) or baghouse control system. The Administrator has determined that these control systems are the best adequately demonstrated technological systems of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, and nonair quality health and environmental impacts and energy requirements).

Electrostatic Precipitators

EPA collected emission data from 21 ESP-equipped steam generating units which were firing low-sulfur coals (0.4–1.9 percent). EPA evaluated emission levels from units burning relatively low-sulfur coal because it is more difficult for an ESP to collect particulate matter emissions generated by the combustion of low-sulfur coal than high-sulfur coal. None of the ESP control systems at the 21 coal-fired steam generators tested were designed to achieve a 13 ng/J (0.03 lb/million Btu) heat input emission level, however, emission levels at 9 of the 21 units were below the standard. All of the units that were firing coal with a sulfur content between 1.0 and 1.9 percent and which had emission levels below the standard had either a hot-side ESP (an ESP located before the combustion air preheater) with a specific collection area greater than 89 square meters per actual cubic meter per second (452 ft^2/1,000 ACFM), or a cold-side ESP (an ESP located after the combustion air preheater) with a specific collection area greater than 85 square meters per actual cubic meter per second (435 ft^2/1,000 ACFM).

ESP's require a larger specific collection area when applied to units burning low-sulfur coal than to units burning high-sulfur coal because the electrical resistivity of the fly ash is higher with low-sulfur coal. Based on an examination of the emission data in the record, it is the Administrator's judgment that when low-sulfur coal is being fired an ESP must have a specific collection area from about 130 (hot side) to 200 (cold side) square meters per actual cubic meter per second (650 to 1,000 ft^2 per 1,000 ACFM) to comply with the standard. When high-sulfur coal (greater than 3.5 percent sulfur) is being fired an ESP must have a specific collection area of about 72 (cold side) square meters per actual cubic meter per second (360 ft^2 per 1,000 ACFM) to comply with the standard.

Cold-side ESP's have traditionally been used to control particulate matter emissions from power plants. The problem of ESP collection of high-electrical-resistivity fly ash from low-sulfur coal can be reduced by using a hot-side ESP. Higher fly ash collection temperatures result in better ESP performance by reducing fly ash resistivity for most types of low-sulfur coal. Reducing fly ash resistivity in itself would decrease the ESP collection plate area needed to meet the standard; however, for a hot-side ESP this benefit is reduced by the increased flue gas volume resulting from the higher flue gas temperature. Although a smaller collection area is required for a hot-side ESP than for a cold side ESP, this benefit is offset by greater construction costs due to the higher quality of materials, thicker insulation, and special design provisions to accommodate the expansion and warping potential of the collection plates.

Baghouses

The Administrator has evaluated data from more than 50 emission test runs conducted at 8 baghouse-equipped coal-fired steam generating units. Although none of these baghouse-controlled units were designed to achieve a 13 Ng/J (0.03 lb/million Btu) heat input emission level, 48 of the test results achieved this level and only 1 test at each of 2 units exceeded 13 Ng/J (0.03 lb/million Btu) heat input. The emission levels at the two units with emission levels above 13 Ng/J (0.03 lb/million Btu) heat input could conceivably be reduced below that level through an improved maintenance program. It is the Administrator's judgment that baghouses with an air-to-cloth ratio of 0.6 actual cubic meter per minute per square meter (2 ACFM/ft^2) will achieve the standard at a pressure drop of less than 1.25 kilopascals (5 in. H_2O). The Administrator has concluded that this air/cloth ratio and pressure drop are reasonable when considering cost, energy, and nonair quality impacts.

When an owner or operator must choose between an ESP and a baghouse to meet the standard, it is the Administrator's judgment that

baghouses have an advantage for low-sulfur coal applications and ESP's have an advantage for high-sulfur coal applications. Available data indicate that for low-sulfur coals, ESP's (hot-side or cold-side) require a large collection area and thus ESP control system costs will be higher than baghouse control system costs. For high-sulfur coals, large collection areas are not required for ESP's, and ESP control systems offer cost savings over baghouse control systems.

Baghouses have not traditionally been used at utility power plants. At the time these regulations were proposed, the largest baghouse-controlled coal-fired steam generator for which EPA had particulate matter emission test data had an electrical output of 44 MW. Several larger baghouse installations were under construction and two larger units were initiating operation. Since the date of proposal of these standards, EPA has tested one of the new units. It has an electrical output capacity of 350 MW and is fired with pulverized, subbituminous coal containing 0.3 percent sulfur. The baghouse control system for this facility is designed to achieve a 43 Ng/J (0.01 lb/million Btu) heat input emission limit. This unit has achieved emission levels below 13 Ng/J (0.03 lb/million Btu) heat input. The baghouse control system was designed with an air-to-cloth ratio of 1.0 actual cubic meter per minute per square meter (3.32 ACFM/ft^2) and a pressure drop of 1.25 kilopascals (5 in. H_2O). Although some operating problems have been encountered, the unit is being operated within its design emission limit and the level of the standard. During the testing the power plant operated in excess of 300 MW electrical output. Work is continuing on the control system to improve its performance. Regardless of type, large emission control systems generally require a period of time for the establishment of cleaning, maintenance, and operational procedures that are best suited for the particular application.

Baghouses are designed and constructed in modules rather than as one large unit. The baghouse control system for the new 350 MW power plant has 28 baghouse modules, each of which services 12.5 MW of generating capacity. As of May 1979, at least 26 baghouse-equipped coal-fired utility steam generators were operating, and an additional 28 utility units are planned to start operation by the end of 1982. About two-thirds of the 30 planned baghouse-controlled power generation systems will have an electrical output capacity greater than 150 MW, and more than one-third of these power plants will be fired with coal containing more than 3 percent sulfur. The Administrator has concluded that baghouse control systems have been adequately demonstrated for full-sized utility application.

Scrubbers

EPA collected emission test data from seven coal-fired steam generators controlled by wet particulate matter scrubbers. Emissions from five of the seven scrubber-equipped power plants were less than 21 Ng/J (0.05 lb/million Btu) heat input. Only one of the seven units had emission test results less than 13 Ng/J (0.03 lb/million Btu) heat input. Scrubber pressure drop can be increased to improve scrubber particulate matter removal efficiencies; however, because of cost and energy considerations, the Administrator believes that wet particulate matter scrubbers will only be used in special situations and generally will not be selected to comply with the standards.

Performance Testing

When the standards were proposed, the Administrator recognized that there is a potential for both FGD sulfate carryover and sulfuric acid mist to affect particulate matter performance testing downstream of an FGD system. Data available at the time of proposal indicated that overall particulate matter emissions, including sulfate carryover, are not increased by a properly designed, constructed, maintained, and operated FGD system. No additional information has been received to alter this finding.

The data available at proposal indicated that sulfuric acid mist (H_2SO_4) interaction with Methods 5 or 17 would not be a problem when firing low-sulfur coal, but may be a problem when firing high-sulfur coals. Limited data obtained since proposal indicate that when high-sulfur coal is being fired, there is a potential for sulfuric acid mist to form after an FGD system and to introduce errors in the performance testing results when Methods 5 or 17 are used. EPA has obtained particulate matter emission test data from two power plants that were fired with coals having more than 3 percent sulfur and that were equipped with both an ESP and FGD system. The particulate matter test data collected after the FGD system were not conclusive in assessing the acid mist problem. The first facility tested appeared to experience a problem with acid mist interaction. The second facility did not appear to experience a problem with acid mist, and emissions after the ESP/FGD system were less than 13 ng/J (0.03 lb/million Btu) heat input. The tests at both facilities were conducted using Method 5, but different methods were used for measuring the filter temperature. EPA has initiated a review of Methods 5 and 17 to determine what modifications may be necessary to avoid acid mist interaction problems. Until these studies are completed the Administrator is approving as an optional test procedure the use of Method 5 (or 17) for performance testing before FGD systems. Performance testing is discussed in more detail in the PERFORMANCE TESTING section of this preamble.

The particulate matter emission limit and opacity limit apply at all times, except during periods of startup, shutdown, or malfunction. Compliance with the particulate matter emission limit is determined through performance tests using Methods 5 or 17. Compliance with the opacity limit is determined by the use of Method 9. A continuous monitoring system to measure opacity is required to assure proper operation and maintenance of the emission control system but is not used for continuous compliance determinations. Data from the continuous monitoring system indicating opacity levels higher than the standard are reported to EPA quarterly as excess emissions and not as violations of the opacity standard.

The environmental impacts of the revised particulate matter standards were estimated by using an economic model of the coal and electric utility industries (see discussion under REGULATORY ANALYSIS). This projection took into consideration the combined effect of complying with the revised SO_2, particulate matter, and NO_x standards on the construction and operation of both new and existing capacity. Particulate matter emissions from power plants were 3.0 million tons in 1975. Under continuation of the current standards, these emissions are predicted to decrease to 1.4 million tons by 1995. The primary reason for this decrease in emissions is the assumption that existing power plants will come into compliance with current state emission regulations. Under these standards, 1995 emissions are predicted to decrease another 400 thousand tons (30 percent).

NO_x Standards

The NO_x emission standards are based on emission levels achievable with a properly designed and operated boiler that incorporates combustion modification techniques to reduce NO_x formation. The levels to which NO_x emissions can be reduced with

combustion modification depend not only upon boiler operating practice, but also upon the type of fuel burned. Consequently, the Administrator has developed fuel-specific NO_x standards. The standards are presented in this preamble under Summary of Standards.

Continuous compliance with the NO_x standards is required, based on a 30-day rolling average. Also, percent reductions in uncontrolled NO_x emission levels are required. The percent reductions are not controlling, however, and compliance with the NO_x emission limits will assure compliance with the percent reduction requirements.

One change has been made to the proposed NO_x standards. The proposed standards would have required compliance to be based on a 24-hour averaging period, whereas the final standards require compliance to be based on a 30-day rolling average. This change was made because several of the comments received, one of which included emission data, indicated that more flexibility in boiler operation on a day-to-day basis is needed to accommodate slagging and other boiler problems that may influence NO_x emissions when coal is burned. The averaging period for determining compliance with the NO_x limitations for gaseous and liquid fuels has been changed from the proposed 24-hour to a 30-day rolling average. This change is necessary to make the compliance times consistent for all fuels. Enforcement of the standards would be complicated by different averaging times, particularly where more than one fuel is used. More details on the selection of the averaging period for coal appear in this preamble under Comments on Proposal.

The proposed standards for coal combustion were based principally on the results of EPA testing performed at six electric utility boilers, all of which are considered to represent modern boiler designs. One of the boilers was manufactured by the Babcock and Wilcox Company (B&W) and was retrofitted with low-emission burners. Four of the boilers were Combustion Engineering, Inc. (CE) designs originally equipped with overfire air, and one boiler was a CE design retrofitted with overfire air. The six boilers burned a variety of bituminous and subbituminous coals. Conclusions drawn from the EPA studies of the boilers were that the most effective combustion modification techniques for reducing NO_x emitted from utility boilers are staged combustion, low excess air, and reduced heat release rate. Low-emission burners were also effective in reducing NO_x levels during the EPA studies.

In developing the proposed standards for coal, the Administrator also considered the following: (1) data obtained from the boiler manufacturers on 11 CE, three B&W, and three Foster Wheeler Energy Corporation (FW) utility boilers; (2) the results of tests performed twice daily over 30-day periods at three well-controlled utility boilers manufactured by CE; (3) a total of six months of continuously monitored NO_x emission data from two CE boilers located at the Colstrip plant of the Montana Power Company; (4) plans underway at B&W, FW, and the Riley Stoker Corporation (RS) to develop low-emission burners and furnace designs; (5) correspondence from CE indicating that it would guarantee its new boilers to achieve, without adverse side-effects, emission limits essentially the same as those proposed; and (6) guarantees made by B&W and FW that their new boilers would achieve the State of New Mexico's NO_x emission limit of 190 ng/J (0.45 lb/million Btu) heat input.

Since proposal of the standards, the following new information has become available and has been considered by the Administrator: (1) additional data from the boiler manufacturers on four B&W and four RS utility boilers; (2) a total of 18 months of continuously monitored NO_x data from the two CE utility boilers at the Colstrip plant; (3) approximately 10 months of continuously monitored NO_x data from five other CE boilers; (4) recent performance test results for a CE and a RS utility boiler; and (5) recent guarantees offered by CE and FW to achieve an NO_x emission limit of 190 ng/J (0.45 lb/million Btu) heat input in the State of California. This and other new information is discussed in "Electric Utility Steam Generating Units, Background Information for Promulgated Emission Standards" (EPA 450/3-79-021).

The data available before and after proposal indicate that NO_x emission levels below 210 ng/J (0.50 lb/million Btu) heat input are achievable with a variety of coals burned in boilers made by all four of the major boiler manufacturers. Lower emission levels are theoretically achievable with catalytic ammonia injection, as noted by several commenters. However, these systems have not been adequately demonstrated at this time on full-size electric utility boilers that burn coal.

Continuously monitored NO_x emission data from coal-fired CE boilers indicate that emission variability during day-to-day operation is such that low NO_x levels can be maintained if emissions are averaged over 30-day periods. Although the Administrator has not been able to obtain continuously monitored data from boilers made by the other boiler manufacturers, the Administrator believes that the emission variability exhibited by CE boilers over long periods of time is also characteristic of B&W, FW, and RS boilers. This is because the Administrator expects B&W, FW, and RS boilers to experience operational conditions which are similar to CE boilers (e.g., slagging, variations in fuel quality, and load reductions) when burning similar fuel. Thus, the Administrator believes the 30-day averaging time is appropriate for coal-fired boilers made by all four manufacturers.

Prior to proposal of the standards several electric utilities and boiler manufacturers expressed concern over the potential for accelerated boiler tube wastage (i.e., corrosion) during low-NO_x operation of a coal-fired boiler. The severity of tube wastage is believed to vary with several factors, but especially with the sulfur content of the coal burned. For example, the combustion of high-sulfur bituminous coal appears to aggravate tube wastage, particularly if it is burned in a reducing atmosphere. A reducing atmosphere is sometimes associated with low-NO_x operation.

The EPA studies of one B&W and five CE utility boilers concluded that tube wastage rates did not significantly increase during low-NO_x operation. The significance of these results is limited, however, in that the tube wastage tests were conducted over relatively short periods of time (30 days or 300 hours). Also, only CE and B&W boilers were studied, and the B&W boiler was not a recent design, but was an old-style unit retrofitted with experimental low-emission burners. Thus, some concern still exists over potentially greater tube wastage during low-NO_x operation when high-sulfur coals are burned. Since bituminous coals often have high sulfur contents, the Administrator has established a special emission limit for bituminous coals to reduce the potential for increased tube wastage during low-NO_x operation.

Based on discussions with the boiler manufacturers and on an evaluation of all available tube wastage information, the Administrator has established an NO_x emission limit of 260 ng/J (0.60 lb/million Btu) heat input for the combustion of bituminous coal. The Administrator believes this is a safe level at which tube wastage will not be accelerated by low-NO_x operation. In

support of this belief, CE has stated that it would guarantee its new boilers, when equipped with overfire air, to achieve the 260 ng/J (0.60 lb/million Btu) heat input limit without increased tube wastage rates when Eastern bituminous coals are burned. In addition, B&W has noted in several recent technical papers that its low-emission burners allow the furnace to be maintained in an oxidizing atmosphere, thereby reducing the potential for tube wastage when high-sulfur bituminous coals are burned. The other boiler manufacturers have also developed techniques that reduce the potential for tube wastage during low-NO_x operation. Although the amount of tube wastage data available to the Administrator on B&W, FW, and RS boilers is very limited, it is the Administrator's judgement that all three of these manufacturers are capable of designing boilers which would not experience increased tube wastage rates as a result of compliance with the NO_x standards.

Since the potential for increased tube wastage during low-NO_x operation appears to be small when low-sulfur subbituminous coals are burned, the Administrator has established a lower NO_x emission limit of 210 ng/J (0.50 lb/million Btu) heat input for boilers burning subbituminous coal. This limit is consistent with emission data from boilers representing all four manufacturers. Furthermore, CE has stated that it would guarantee its modern boilers to achieve an NO_x limit of 210 ng/J (0.50 lb/million Btu) heat input, without increased tube wastage rates, when subbituminous coals are burned.

The emission limits for electric utility power plants that burn liquid and gaseous fuels are at the same levels as the emission limits originally promulgated in 1971 under 40 CFR Part 60, Subpart D for large steam generators. It was decided that a new study of combustion modification or NO_x flue-gas treatment for oil- or gas-fired electric utility steam generators would not be appropriate because few, if any, of these kinds of power plants are expected to be built in the future.

Several studies indicate that NO_x emissions from the combustion of fuels derived from coal, such as liquid solvent-refined coal (SRC II) and low-Btu synthetic gas, may be higher than those from petroleum oil or natural gas. This is because coal-derived fuels have fuel-bound nitrogen contents that approach the levels found in coal rather than those found in petroleum oil and natural gas. Based on limited emission data from pilot-scale facilities and on the known emission characteristics of coal, the Administrator believes that an achievable emission limit for solid, liquid, and gaseous fuels derived from coal is 210 ng/J (0.50 lb/million Btu) heat input. Tube wastage and other boiler problems are not expected to occur from boiler operation at levels as low as 210 ng/J when firing these fuels because of their low sulfur and ash contents.

NO_x emission limits for lignite combustion were promulgated in 1978 (48 FR 9276) as amendments to the original standards under 40 CFR Part 60, Subpart D. Since no new information on NO_x emission rates from lignite combustion has become available, the emission limits have not been changed for these standards. Also, these emission limits are the same as the proposed.

Little is known about the emission characteristics of shale oil. However, since shale oil typically has a higher fuel-bound nitrogen content than petroleum oil, it may be impossible for a well-controlled unit burning shale oil to achieve the NO_x emission limit for liquid fuels. Shale oil does have a similar nitrogen content to coal, and it is reasonable to expect that the emission control techniques used for coal could also be used to limit NO_x emissions from shale oil combustion. Consequently, the Administrator has limited NO_x emissions from units burning shale oil to 210 ng/J (0.50 lb/million Btu) heat input, the same limit applicable to subbituminous coal, which is the same as proposed. There is no evidence that tube wastage or other boiler problems would result from operation of a boiler at 210 ng/J when shale oil is burned.

The combustion of coal refuse was exempted from the original steam generator standards under 40 CFR Part 60, Subpart D because the only furnace design believed capable of burning certain kinds of coal refuse, the slag tap furnace, inherently produces NO_x emissions in excess of the NO_x standard. Unlike lignite, virtually no NO_x emission data are available for the combustion of coal refuse in slag tap furnaces. The Administrator has decided to continue the coal refuse exemption under the standards promulgated here because no new information on coal refuse combustion has become available since the exemption under Subpart D was established.

The environmental impacts of the revised NO_x standards were estimated by using an economic model of the coal and electric utility industries (see discussion under REGULATORY ANALYSIS). This projection took into consideration the combined effect of complying with the revised SO_2, particulate matter, and NO_x standards on the construction and operation of both new and existing capacity. National NO_x emissions from power plants were 6.8 million tons in 1975 and are predicted to increase to 9.3 million tons by 1995 under the current standards. These standards are projected to reduce 1995 emissions by 600 thousand tons (6 percent).

Background

In December 1971, under section 111 of the Clean Air Act, the Administrator issued standards of performance to limit emissions of SO_2, particulate matter, and NO_x from new, modified, and reconstructed fossil-fuel-fired steam generators (40 CFR 60.40 et seq.). Since that time, the technology for controlling emissions from this source category has improved, but emissions of SO_2, particulate matter, and NO_x continue to be a national problem. In 1976, steam electric generating units contributed 24 percent of the particulate matter, 65 percent of the SO_2, and 29 percent of the NO_x emissions on a national basis.

The utility industry is expected to have continued and significant growth. The capacity is expected to increase by about 50 percent with approximate 300 new fossil-fuel-fired power plant boilers to begin operation within the next 10 years. Associated with utility growth is the continued long-term increase in utility coal consumption from some 400 million tons/year in 1975 to about 1250 million tons/year in 1995. Under the current performance standards for power plants, national SO_2 emissions are projected to increase approximately 17 percent between 1975 and 1995.

Impacts will be more dramatic on a regional basis. For example, in the absence of more stringent controls, utility SO_2 emissions are expected to increase 1300 percent by 1995 in the West South Central region of the country (Texas, Oklahoma, Arkansas, and Louisiana).

EPA was petitioned on August 6, 1976, by the Sierra Club and the Oljato and Red Mesa Chapters of the Navaho Tribe to revise the SO_2 standard so as to require a 90 percent reduction in SO_2 emissions from all new coal-fired power plants. The petition claimed that advances in technology since 1971 justified a revision of the standard. As a result of the petition, EPA agreed to investigate the matter thoroughly. On January 27, 1977 (42 FR 5121), EPA announced that it had initiated a study to review the technological, economic, and other factors needed to determine to

what extent the SO_2 standard for fossil-fuel-fired steam generators should be revised.

On August 7, 1977, President Carter signed into law the Clean Air Act Amendments of 1977. The provisions under section 111(b)(6) of the Act, as amended, required EPA to revise the standards of performance for fossil-fuel-fired electric utility steam generators within 1 year after enactment.

After the Sierra Club petition of August 1976, EPA initiated studies to review the advancement made on pollution control systems at power plants. These studies were continued following the amendment of the Clean Air Act. In order to meet the schedule established by the Act, a preliminary assessment of the ongoing studies was made in late 1977. A National Air Pollution Control Techniques Advisory Committee meeting was held on December 13 and 14, 1977, to present EPA preliminary data. The meeting was open to the public and comments were solicited.

The Clean Air Act Amendments of 1977 required the standards to be revised by August 7, 1978. When it appeared that the Administrator would not meet this schedule, the Sierra Club filed a complaint on July 14, 1978, with the U.S. District Court for the District of Columbia requesting injunctive relief to require, among other things, that the Administrator propose the revised standards by August 7, 1978 (Sierra Club v. Costle, No. 78-1297). The Court approved a stipulation requiring the Administrator to (1) deliver proposed regulations to the Office of the Federal Register by September 12, 1978, and (2) promulgate the final regulations within 6 months after proposal (i.e., by March 19, 1979).

The Administrator delivered the proposal package to the Office of the Federal Register by September 12, 1978, and the proposed regulations were published September 19, 1978 (43 FR 42154). Public comments on the proposal were requested by December 15, and a public hearing was held December 12 and 13, the record of which was held open until January 15, 1979. More than 625 comment letters were received on the proposal. The comments were carefully considered, however, the issues could not be sufficiently evaluated in time to promulgate the standards by March 19, 1979. On that date the Administrator and the other parties in Sierra Club v. Costle filed with the Court a stipulation whereby the Administrator would sign and deliver the final standards to the Federal Register on or before June 1, 1979.

The Administrator's conclusions and responses to the major issues are presented in this preamble. These regulations represent the Administrator's response to the petition of the Navaho Tribe and Sierra Club and fulfill the rulemaking requirements under section 111(b)(6) of the Act.

Applicability

General

These standards apply to electric utility steam generating units capable of firing more than 73 MW (250 million Btu/hour) heat input of fossil fuel, for which construction is commenced after September 18, 1978. This is principally the same as the proposal. Some minor changes and clarification in the applicability requirements for cogeneration facilities and resource recovery facilities have been made.

On December 23, 1971, the Administrator promulgated, under Subpart D of 40 CFR Part 60, standards of performance for fossil-fuel-fired steam generators used in electric utility and large industrial applications. The standards adopted herein do not apply to electric utility steam generating units originally subject to those standards (Subpart D) unless the affected facilities are modified or reconstructed as defined under 40 CFR 60 Subpart A and this subpart. Similarly, units constructed prior to December 23, 1971, are not subject to either performance standard (Subpart D or Da) unless they are modified or reconstructed.

Electric Utility Steam Generating Units

An electric utility steam generating unit is defined as any steam electric generating unit that is physically connected to a utility power distribution system and is constructed for the purpose of selling more than 25 MW electrical output and more than one third of its potential electrical output capacity. Any steam that is sold and ultimately used to produce electrical power for sale through the utility power distribution system is also included under the standard. The term "potential electrical generating capacity" has been added since proposal and is defined as 33 percent of the heat input rate at the facility. The applicability requirement of selling more than 25 MW electrical output capacity has also been added since proposal.

These standards cover industrial steam electric generating units or cogeneration units (producing steam for both electrical generation and process heat) that are capable of firing more than 73 MW (250 million Btu/hr) heat input of fossil fuel and are constructed for the purpose of selling through a utility power distribution system more than 25 MW electrical output and more than one-third of their potential electrical output capacity (or steam generating capacity ultimately used to produce electricity for sale). Facilities with a heat input rate in excess of 73 MW (250 million Btu/hour) that produce only industrial steam or that generate electricity but sell less than 25 MW electrical output through the utility power distribution system or sell less than one-third of their potential electric output capacity through the utility power distribution system are not covered by these standards, but will continue to be covered under Subpart D, if applicable.

Resource recovery units incorporating steam electric generating units that would meet the applicability requirements but that combust less than 25 percent fossil fuel on a quarterly (90-day) heat-input basis are not covered by the SO_2 percent reduction requirements under this standard. These facilities are subject to the SO_2 emission limitation and all other provisions of the regulation. They are also required to monitor their heat input by fuel type and to monitor SO_2 emissions. If more than 25 percent fossil fuel is fired on a quarterly heat input basis, the facility will be subject to the SO_2 percent reduction requirements. This represents a change from the proposal which did not include such provisions.

These standards cover steam generator emissions from electric utility combined-cycle gas turbines that are capable of being fired with more than 73 MW (250 million Btu/hr) heat input of fossil fuel and meet the other applicability requirements. Electric utility combined-cycle gas turbines that use only turbine exhaust gas to provide heat to a steam generator (waste heat boiler) or that incorporate steam generators that are not capable of being fired with more than 73 MW (250 million Btu/hr) of fossil fuel are not covered by the standards.

Modification/Reconstruction

Existing facilities are only covered by these standards if they are modified or reconstructed as defined under Subpart A of 40 CFR Part 60 and this standard (Subpart Da).

Few, if any, existing facilities that change fuels, replace burners, etc. will be covered by these standards as a result of the modification/reconstruction provisions. In particular, the standards do not apply to existing facilities that are modified to fire nonfossil fuels or to

existing facilities that were designed to fire gas or oil fuels and that are modified to fire shale oil, coal/oil mixtures, coal/oil/water mixtures, solvent refined coal, liquified coal, gasified coal, or any other coal-derived fuel. These provisions were included in the proposal but have been clarified in the final standard.

Comments on Proposal

Electric Utility Steam Generating Units

The applicability requirements are basically the same as those in the proposal; electric utility steam generating units capable of firing greater than 73 MW (250 million Btu/hour) heat input of fossil fuel for which construction is commenced after September 18, 1978, are covered. Since proposal, changes have been made to specific applicability requirements for industrial cogeneration facilities, resource recovery facilities, and anthracite coal-fired facilities. These revisions are discussed later in this preamble.

Only a limited number of comments were received on the general applicability provisions. Some commenters expressed the opinion that the standards should apply to both industrial boilers and electric utility steam generating units. Industrial boilers are not covered by these standards because there are significant differences between the economic structure of utilities and the industrial sector. EPA is currently developing standards for industrial boilers and plans to propose them in 1980.

Cogeneration Facilities

Cogeneration facilities are covered under these standards if they have the capability of firing more than 73 MW (250 million Btu/hour) heat input of fossil fuel and are constructed for the purpose of selling more than 25 MW of electricity and more than one-third of their potential electrical output capacity. This reflects a change from the proposed standards under which facilities selling less than 25 MW of electricity through the utility power distribution system may have been covered.

A number of commenters suggested that industrial cogeneration facilities are expected to be highly efficient and that their construction could be discouraged if the proposed standards were adopted. The commenters pointed out that industrial cogeneration facilities are unusual in that a small capacity (10 MW electric output capacity, for example) steam-electric generating set may be matched with a much larger industrial steam generator (larger than 250 million Btu/hr for example). The Administrator intended that the proposed standards cover only electric generation sets that would sell more than 25 MW electrical output on the utility power distribution system. The final standards allow the sale of up to 25 MW electrical output capacity before a facility is covered. Since most industrial cogeneration units are expected to be less than 25 MW electrical output capacity, few, if any, new industrial cogeneration units will be covered by these standards. The standards do cover large electric utility cogeneration facilities because such units are fundamentally electric utility steam generating units.

Comments suggested clarifying what was meant in the proposal by the sale of more than one-third of its "maximum electrical generating capacity". Under the final standard the term "potential electric output capacity" is used in place of "maximum electrical generating capacity" and is defined as 33 percent of the steam generator heat input capacity. Thus, a steam generator with a 500 MW (1,700 million Btu/hr) heat input capacity would have a 165 MW potential electrical output capacity and could sell up to one-third of this potential output capacity on the grid (55 MW electrical output) before being covered under the standard. Under the proposal, it was unclear if the standard allowed the sale of up to one-third of the actual electric generating capacity of a facility or one-third of the potential generating capacity before being covered under the standards. The Administrator has clarified his intentions in these standards. Without this clarification the standards may have discouraged some industrial cogeneration facilities that have low in-house electrical demand.

A number of commenters suggested that emission credits should be allowed for improvements in cycle efficiency at new electric utility power plants. The commenters suggested that the use of electrical cogeneration technology and other technologies with high cycle efficiencies could result in less overall fuel consumption, which in turn could reduce overall environmental impacts through lower air emissions and less solid waste generation. The final standards do not give credit for increases in cycle efficiency because the different technologies covered by the standards and available for commercial application at this time are based on the use of conventional steam generating units which have very similar cycle efficiencies, and credits for improved cycle efficiency would not provide measurable benefits. Although the final standards do not address cycle efficiency, this approach will not discourage the application of more efficient technologies.

If a facility that is planned for construction will incorporate an innovative control technology (including electrical generation technologies with inherently low emissions or high electrical generation efficiencies) the owner or operator may apply to the Administrator under section 111(j) of the Act for an innovative technology waiver which will allow for (1) up to four years of operation or (2) up to seven years after issuance of a waiver prior to performance testing. The technology would have to have a substantial likelihood of achieving greater continuous emission reduction or achieve equivalent reductions at low cost in terms of energy, economics, or nonair quality impacts before a waiver would be issued.

Resource Recovery Facilities

Electric utility steam generating units incorporated into resource recovery facilities are exempt from the SO_2 percent reduction requirements when less than 25 percent of the heat input is from fossil fuel on a quarterly heat input basis. Such facilities are subject to all other requirements of this standard. This represents a change from the proposed regulation, under which any steam electric generating unit that combusts non-fossil fuels such as wood residue, sewage sludge, waste material, or municipal refuse would have been covered if the facility were capable of firing more than 75 MW (250 million Btu/hr) of fossil fuel.

A number of comments indicated that the proposed standard could discourage the construction of resource recovery facilities that generate electricity because of the SO_2 percentage reduction requirement. One commenter suggested that most new resource recovery facilities will process municipal refuse and other wastes into a dry fuel with a low-sulfur content that can be stored and subsequently fired. The commenter suggested that when firing processed refuse fuel, little if any fossil fuel will be necessary for combustion stabilization over the long term; however, fossil fuel will be necessary for startup. When a cold unit is started, 100 percent fossil fuel (oil or gas) may be fired for a few hours prior to firing 100 percent processed refuse.

Other commenters suggested that resource recovery facilities would in many cases be owned and operated by a municipality and the electricity and

steam generated would be sold by contract to offset operating costs. Under such an arrangement, commenters suggested that there may be a need to fire fossil fuel on a short-term basis when refuse is not readily available in order to generate a reliable supply of steam for the contract customer.

The Administrator accepts these suggestions and does not wish to discourage the construction of resource recovery facilities that generate electricity and/or industrial steam. For resource recovery facilities, the Administrator believes that less than 25 percent heat input from fossil fuels will be required on a long-term basis; even though 100 percent fossil fuel firing [greater than 73 MW (250 million Btu/hour)] may be necessary for startup or intermittent periods when refuse is not available. During startup such units are allowed to fire 100 percent fossil fuel because periods of startup are exempt from the standards under 40 CFR 60.8(c). If a reliable source of refuse is not available and 100 percent fossil fuel is to be fired more than 25 percent of the time, the Administrator believes it is reasonable to require such units to meet the SO_2 percent reduction requirements. This will allow resource recovery facilities to operate with fossil fuel up to 25 percent of the time without having to install and operate an FGD system.

Anthracite

These standards exempt facilities that burn anthracite alone from the percentage reduction requirements of the SO_2 standard but cover them under the 520 ng/J (1.2 lb/million Btu) heat input emission limitation and all requirements of the particulate matter and NO_x standards. The proposed regulations would have covered anthracite in the same maner as all other coals. Since the Administrator recognized that there were arguments in favor of less stringent requirements for anthracite, this issue was discussed in the preamble to the proposed regulations.

Over 30 individuals or organizations commented on the anthracite issue. Almost all of the commenters favored exempting anthracite from the SO_2 percentage reduction requirement. Some of the reasons cited to justify exemption were: (1) the sulfur content of anthracite is low; (2) anthracite is more expensive to mine and burn than bituminous and will not be used unless it is cost competitive; and (3) reopening the anthracite mines will result in improvement of acid-mine-water conditions, elimination of old mining scars on the topography, eradication of dangerous fires in deep mines and culm banks, and creation of new jobs. One commenter pointed out that the average sulfur content of anthracite is 1.09 percent. Other commenters indicated that anthracite will be cleaned, which will reduce the sulfur content. One commenter opposed exempting anthracite, because it would result in more SO_2 emissions. Another commenter said all coal-fired power plants including anthracite-fired units should have scrubbers.

After evaluating all of the comments, the Administrator has decided to exempt facilities that burn anthracite alone from the percentage reduction requirements of the SO_2 standard. These facilities will be subject to all other requirements of this regulation, including the particulate matter and NO_x standards, and the 520 ng/J (1.2 lb/million Btu) heat imput emission limitation under the SO_2 standard.

In 10 Northeastern Pennsylvania counties, where about 95 percent of the nation's anthracite coal reserves are located, approximately 40,000 acres of land have been despoiled from previous anthracite mining. The recently enacted Federal Surface Mining Control and Reclamation Act was passed to provide for the reclamation of areas like this. Under this Act, each ton of coal mined is taxed at 35 cents for strip mining and 15 cents for deep mining operations. One-half of the amount taxed is automatically returned to the State where the coal mined and one-half is to be distributed by the Department of Interior. This tax is expected to lead eventually to the reclamation of the anthracite region, but restoration will require many years. The reclamation will occur sooner if culm piles are used for fuel, the abandoned mines are reopened, and the expense of reclamation is born directly by the mine operator.

The Federal Surface Mining Control and Reclamation Act and a similar Pennsylvania law also provide for the establishment of programs to regulate anthracite mining. The State of Pennsylvania has assured EPA that total reclamation will occur if anthracite mining activity increases. They are actively pursuing with private industry the development of one area involving 12,000 to 19,000 acres of despoiled land.

In Summary, the Administrator concludes that the higher SO_2 emissions resulting from the use of anthracite without a flue gas desulfurization system is acceptable because of the other environmental improvements that will result. The impact of facilities using anthracite on ambient air quality will be minimized, because they will have to be reviewed to assure compliance with the prevention of significant deterioration provisions under the Act.

Alaskan Coal

The final standards are the same as the proposed; facilities fired with Alaskan coal are covered in the same manner as facilities fired with other coals.

Commenters suggested that problems unique to Alaska justify special provisions for facilities located in Alaska and firing Alaskan coal. Reasons cited as justification for less stringent standards by commenters on the proposal were freezing conditions, problems with sludge disposal, adverse impact of FGD on the reliability of plant operation, low-sulfur content of the coal, and cost impact on the consumer. The Administrator has examined these factors and has concluded that technically and economically feasible means are available to overcome these problems; therefore special regulatory provisions are not justified.

In reaching this conclusion the Administrator considered whether these factors demonstrated that the standards posed a substantially greater burden unique to Alaska. In other northern States where severe freezing conditions are common, plants are enclosed in buildings and insulated vessels and piping provide protection from freezing, both for scrubber operation and for liquid sludge dewatering. For an equivalent electrical generating capacity, the disposal sites for Alaskan plants could be smaller than those for most plants in the contiguous 48 States because of the lower sulfur content of Alaskan coal. Burying pipes carrying sludge to waste ponds below the frost line is feasible, except possibly in permafrost areas. The Administrator expects that future steam generators cannot be sited in permafrost areas because fly ash as well as scrubber sludge could not be properly disposed of in accordance with requirements of the Resource Recovery and Reclamation Act. In permafrost areas, turbines or other non-waste-producing processes are used or electricity is transmitted from other locations.

One commenter pointed out that failures of the FGD system would have an adverse impact on the ability to supply customers with reliable electric service, since there are no extensive interconnections with other utility companies. The Administrator has provided relief from the standards under emergency conditions that would require a choice between meeting a

power demand or complying with the standards. These emergency provisions are discussed in a subsequent section of this preamble.

Concern was expressed by the commenters that the cost impact of the standard would be excessive and that the benefits do not justify the cost, especially since Alaskan coal is among the lowest sulfur-content coal in the country. The Administrator agrees that for comparable sulfur-content coals, scrubber operating costs are slightly higher in Alaska because of the transportation costs of required materials such as lime. However, the operating costs are lower than the typical costs of FGD units controlling emissions from higher sulfur coals in the contiguous 48 States.

The Administrator considered applying a less stringent SO_2 standard to Alaskan coal-fired units, but concluded that there is insufficient distinction between conditions in Alaska and conditions in the northern part of the contiguous 48 States to justify such action. The Administrator has concluded that Alaskan coal-fired units should be controlled in the same manner as other facilities firing low-sulfur coal.

Noncontinental Areas

Facilities in noncontinental areas (State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Mariana Islands) are exempt from the SO_2 percentage reduction requirements. Such facilities are required, however, to meet the SO_2 emission limitations of 520 ng/J (1.2 lb/million Btu) heat input (30-day rolling average) for coal and 340 ng/J (0.8 lb/million Btu) heat input (30-day rolling average) for oil, in addition to all requirements under the NO_x and particulate matter standards. This is the same as the proposed standards.

Although this provision was identified as an issue in the preamble to the proposed standards, very few comments were received on it. In general, the comments supported the proposal. The main question raised is whether Puerto Rico has adequate land available for sludge disposal.

After evaluating the comments and available information, the Administrator has concluded that noncontinental areas, including Puerto Rico, are unique and should be exempt from the SO_2 percentage reduction requirements.

The impact of new power plants in noncontinental areas on ambient air quality will be minimized because each will have to undergo a review to assure compliance with the prevention of significant deterioration provisions under the Clean Air Act. The Administrator does not intend to rule out the possibility that an individual BACT or LAER determination for a power plant in a noncontinental area may require scrubbing.

Emerging Technology

The final regulations for emerging technologies are summarized earlier in this preamble under SUMMARY OF STANDARDS and are very similar to the proposed regulations.

In general, the comments received on the proposed regulations were supportive, although a few commenters suggested some changes. A few commenters indicated that section 111(j) of the Act provides EPA with authority to handle innovative technologies. Some commenters pointed out that the proposed standards did not address certain technologies such as dry scrubbers for SO_2 control. One commenter suggested that SRC I should be included under the solvent refined coal rather than coal liquefaction category for purposes of allocating the 15,000 MW equivalent electrical capacity.

On the basis of the comments and public record, the Administrator believes the need still exists to provide a regulatory mechanism to allow a less stringent standard to the initial full-scale demonstration facilities of certain emerging technologies. At the time the standards were proposed, the Administrator recognized that the innovative technology waiver provisions under section 111(j) of the Act are not adequate to encourage certain capital-intensive, front-end control technologies. Under the innovative technology provisions, the Administrator may grant waivers for a period of up to 7 years from the date of issuance of a waiver or up to 4 years from the start of operation of a facility, whichever is less. Although this amount of time may be sufficient to amortize the cost of tail-gas control devices that do not achieve their design control level, it does not appear to be sufficient for amortization of high-capital-cost, front-end control technologies. The proposed provisions were designed to mitigate the potential impact on emerging front-end technologies and insure that the standards do not preclude the development of such technologies.

Changes have been made to the proposed regulations for emerging technologies relative to averaging time in order to make them consistent with the final NO_x and SO_2 standards; however, a 24-hour averaging period has been retained for SRC-I because it has relatively uniform emission rates, which makes a 24-hour averaging period more appropriate than a 30-day rolling average.

Commercial demonstration permits establish less stringent requirements for the SO_2 or NO_x standards, but do not exempt facilities with these permits from any other requirements of these standards.

Under the final regulations, the Administrator (in consultation with the Department of Energy) will issue commercial demonstration permits for the initial full-scale demonstration facilities of each specified technology. These technologies have been shown to have the potential to achieve the standards established for commercial facilities. If, in implementing these provisions, the Administrator finds that a given emerging technology cannot achieve the standards for commercial facilities, but it offers superior overall environmental performance (taking into consideration all areas of environmental impact, including air, water, solid waste, toxics, and land use) alternative standards can be established.

It should be noted that these permits will only apply to the application of this standard and will not supersede the new source review procedures and prevention of significant deterioration requirements under other provisions of the Act.

Modification/Reconstruction

The impact of the modification/reconstruction provisions is the same for the final standard as it was for the proposed standard; existing facilities are only covered by the final standards if the facilities are modified or reconstructed as defined under 40 CFR 60.14, 60.15, or 60.40a. Many types of fuel switches are expressly exempt from modification/reconstruction provisions under section 111 of the Act.

Few, if any, existing steam generators that change fuels, replace burners, etc., are expected to qualify under the modification/reconstruction provisions; thus, few, if any, existing electric utility steam generating units will become subject to these standards.

The preamble to the proposed regulations did not provide a detailed discussion of the modification/reconstruction provisions, and the comments received indicated that these provisions were not well understood by the commenters. The general modification/reconstruction provisions under 40 CFR 60.14 and 60.15 apply to all source categories covered under Part 60. Any source-specific modification/

reconstruction provisions are defined in more detail under the applicable subpart (60.40a for this standard).

A number of commenters expressly requested that fuel switching provisions be more clearly addressed by the standard. In response, the Administrator has clarified the fuel switching provisions by including them in the final standards. Under these provisions existing facilities that are converted to nonfossil fuels are not considered to have undergone modification. Similarly, existing facilities designed to fire gas or oil and that are converted to shale oil, coal/oil mixtures, coal/oil/water mixtures, solvent refined coal, liquified coal, gasified coal, or any other coal-derived fuel are not considered to have undergone modification. This was the Administrator's intention under the proposal and was mentioned in the Federal Register preamble for the proposal.

SO_2 Standards

SO_2 Control Technology—The final SO_2 standards are based on the performance of a properly designed, installed, operated and maintained FGD system. Although the standards are based on lime and limestone FGD systems, other commercially available FGD systems (e.g., Wellman-Lord, double alkali and magnesium oxide) are also capable of achieving the final standard. In addition, when specifying the form of the final standards, the Administrator considered the potential of dry SO_2 control systems as discussed later in this section.

Since the standards were proposed, EPA has continued to collect SO_2 data with continuous monitors at two sites and initiated data gathering at two additional sites. At the Conesville No. 5 plant of Columbus and Southern Ohio Electric company, EPA gathered continuous SO_2 data from July to December 1978. The Conesville No. 5 FGD unit is a turbulent contact absorber (TCA) scrubber using thiosorbic lime as the scrubbing medium. Two parallel modules handle the gas flow from a 411-MW boiler firing run-of-mine 4.5 percent sulfur Ohio coal. During the test period, data for only thirty-four 24-hour averaging periods were gathered because of frequent boiler and scrubber outages. The Conesville system averaged 88.8 percent SO_2 removal, and outlet SO_2 emissions averaged 0.80 lb/million Btu. Monitoring of the Wellman-Lord FGD unit at Northern Indiana Public Service Company's Mitchell station during 1978 included one 41-day continuous period of operation. Data from this period were combined with previous data and analyzed. Results indicated 0.61 lb SO_2/million Btu and 89.2 percent SO_2 removal for fifty-six 24-hour periods.

From December 1978 to February 1979, EPA gathered SO_2 data with continuous monitors at the 10-MW prototype unit (using a TCA absorber with lime) at Tennessee Valley Authority's (TVA) Shawnee station and the Lawrence No. 4 FGD unit (using limestone) of Kansas Power and Light Company. During the Shawnee test, data were obtained for forty-two 24-hour periods in which 3.0 percent sulfur coal was fired. Sulfur dioxide removal averaged 88.6 percent. Lawrence No. 4 consists of a 125-MW boiler controlled by a spray tower limestone FGD unit. In January and February 1979, during twenty-two 24-hour periods of operation with 0.5 percent sulfur coal, the average SO_2 removal was 96.6 percent. The Shawnee and Lawrence tests also demonstrated that SO_2 monitors can function with reliabilities above 80 percent. A summary of the recent EPA-acquired SO_2 monitored data follows:

Site	Scrubber	Coal sulfur, pct.	No. of 24-hour periods	Average SO_2 removal, pct.
Conesville No. 5	Thiosorbic lime/TCA	4.5	34	89.2
NIPSCO	Wellman-Lord	3.5	56	89.2
Shawnee	Lime/TCA	3.0	42	88.6
Lawrence No. 4	Limestone/spray tower	0.5	22	96.6

Since proposing the standards, EPA has prepared a report that updates information in the earlier PEDCo report on FGD systems. The report includes listings of several new closed-loop systems.

A variety of comments were received concerning SO_2 control technology. Several comments were concerned with the use of data from FGD systems operating in Japan. These comments suggested that the Japanese experience shows that technology exists to obtain greater than 90 percent SO_2 removal. The commenters pointed out that attitudes of the plant operators, the skill of the FGD system operators, the close surveillance of power plant emissions by the Japanese Government, and technical differences in the mode of scrubber operation were primary factors in the higher FGD reliabilities and efficiencies for Japanese systems. These commenters stated that the Japanese experience is directly applicable to U.S. facilities. Other comments stated that the Japanese systems cannot be used to support standards for power plants in the U.S. because of the possible differences in factors such as the degree of closed-loop versus open-loop operation, the impact of trace constituents such as chlorides, the differences in inlet SO_2 concentrations, SO_2 uptake per volume of slurry, Japanese production of gypsum instead of sludge, coal blending and the amount of maintenance.

The comments on closed-loop operation of Japanese systems inferred that larger quantities of water are purged from these systems than from their U.S. counterparts. A closed-loop system is one where the only water leaving the system is by: (1) evaporative water losses in the scrubber, and (2) the water associated with the sludge. The administrator found by investigating the systems referred to in the comments that six of ten Japanese systems listed by one commenter and two of four coal-fired Japanese systems are operated within the above definition of closed-loop. The closed-loop operation of Japanese scrubbers was also attested to in an Interagencey Task Force Report, "Sulfur Oxides Control Technology in Japan" (June 30, 1978) prepared for Honorable Henry M. Jackson, Chairman, Senate Committee on Energy and Natural Resources. It is also important to note that several of these successful Japanese systems were designed by U.S. vendors.

After evaluating all the comments, the Administrator has concluded that the experience with systems in Japan is applicable to U.S. power plants and can be used as support to show that the final standards are achievable.

A few commenters stated that closed-loop operation of an FGD system could not be accomplished, especially at utilities burning high-sulfur coal and located in areas where rainfall into the sludge disposal pond exceeds evaporation from the pond. It is important to note that neither the proposed nor final standards require

closed-loop operation of the FGD. The commenters are primarily concerned that future water pollution regulations will require closed-loop operation. Several of these commenters ignored the large amount of water that is evaporated by the hot exhaust gases in the scrubber and the water that is combined with and goes to disposal with the sludge in a typical ponding system. If necessary, the sludge can be dewatered by use of a mechanical clarifier, filter, or centrifuge and then sludge disposed of in a landfill designed to minimize rainwater collection. The sludge could also be physically or chemically stabilized.

Most U.S. systems operate open-loop (i.e., have some water discharge from their sludge pond) because they are not required to do otherwise. In a recent report "Electric Utility Steam Generating Units—Flue Gas Desulfurization Capabilities as of October 1978" (EPA-450/3-79-001), PEDCo reported that several utilities burning both low- and high-sulfur coal have reported that they are operating closed-loop FGD systems. As discussed earlier, systems in Japan are operating closed-loop if pond disposal is included in the system. Also, experiments at the Shawnee test facility have shown that highly reliable operation can be achieved with high sulfur coal (containing moderate to high levels of chloride) during closed-loop operation. The Administrator continues to believe that although not required, closed-loop operation is technically and economically feasible if the FGD and disposal system are properly designed. If a water purge is necessary to control chloride buildup, this stream can be treated prior to disposal using commercially available water treatment methods, as discussed in the report "Controlling SO_2 Emissions from Coal-Fired Steam-Electric Generators: Water Pollution Impact" (EPA-600/7-78-045b).

Two comments endorsed coal cleaning as an SO_2 emission control technique. One commenter encouraged EPA to study the potential of coal cleaning, and another endorsed coal cleaning in preference to FGD. The Administrator investigated coal cleaning and the relative economics of FGD and coal cleaning and the results are presented in the report "Physical Coal Cleaning for Utility Boiler SO_2 Emission Control" (EPA-600/7-78-034). The Administrator does not consider coal cleaning alone as representing the best demonstrated system for SO_2 emission reduction. Coal cleaning does offer the following benefits when used in conjuction with an FGD system: (1) the SO_2 concentrations entering the FGD system are lower and less variable than would occur without coal cleaning, (2) percent removal credit is allowed toward complying with the SO_2 standard percent removal requirement, and (3) the SO_2 emission limit can be achieved when using a coal having a sulfur content above that which would be needed when coal cleaning is not practiced. The amount of sulfur that can be removed from coal by physical coal cleaning was investigated by the U.S. Department of the Interior ("Sulfur Reduction Potential of the Coals of the United States," Bureau of Mines Report of Investigations/1976, RI-8118). Coal cleaning principally removes pyritic sulfur from coal by crushing it to a maximum top size and then separating the pyrites and other rock impurities from the coal. In order to prevent coal cleaning processes from developing into undesirable sources of energy waste, the amount of crushing and the separation bath's specific gravity must be limited to reasonable levels. The Administrator has concluded that crushing to 1.5 inches topsize and separation at 1.6 specific gravity represents common practice. At this level, the sulfur reduction potential of coal cleaning for the Eastern Midwest (Illinois, Indiana, and Western Kentucky) and the Northern Appalachian Coal (Pennsylvania, Ohio, and West Virginia) regions averages approximately 30 percent. The washability of specific coal seams will be less than or more than the average.

Some comments state that FGD systems do not work on specific coals, such as high-sulfur Illinois-Indiana coal, high-chloride Illinois coal, and Southern Appalachian coals. After review of the comments and data, the Administrator concluded that FGD application is not limited by coal properties. Two reports, "Controlling SO_2 Emissions from Coal-Fired Steam-Electric Generators: Water Pollution Impact" (EPS-600/7-78-045b) and "Flue Gas Desulfurization Systems: Design and Operating Considerations" (EPA-600/7-78-030b) acknowledge that coals with high sulfur or -chloride content may present problems. Chlorides in flue gas replace active calcium, magnesium, or sodium alkalis in the FGD system solution and cause stress corrosion in susceptible materials. Prescrubbing of flue gas to absorb chlorides upstream of the FGD or the use of alloy materials and protective coatings are solutions to high-chloride coal applications. Two reports, "Flue Gas Desulfurization System Capabilities for Coal-Fired Steam Generators" (EPA-600/7-78-032b) and "Flue Gas Desulfurization Systems: Design and Operating Considerations" (EPA -600/7-7-78-030b) also acknowledge that 90 percent SO_2 removal (or any given level) is more difficult when burning high-sulfur coal than when burning low-sulfur coal because the mass of SO_2 that must be removed is greater when high-sulfur coal is burned. The increased load results in larger and more complex FGD systems (requiring higher liquid-to-gas ratios, larger pumps, etc). Operation of current FGD installations such as LaCygne with over 5 percent sulfur coal, Cane Run No. 4 on high-sulfur midwestern coal, and Kentucky Utilities Green River on 4 percent sulfur coal provides evidence that complex systems can be operated successfully on high-sulfur coal. Recent experience at TVA, Widows Creek No. 8 shows that FGD systems can operate successfully at high SO_2 removal efficiencies when Southern Appalachian coals are burned.

Coal blending was the subject of two comments: (1) that blending could reduce, but not eliminate, sulfur variability; and (2) that coal blending was a relatively inexpensive way to meet more relaxed standards. The Administrator believes that coal blending, by itself, does not reduce the average sulfur content of coal but reduces the variability of the sulfur content. Coal blending is not considered representative of the best demonstrated system for SO_2 emission reduction. Coal blending, like coal cleaning, can be beneficial to the operation of an FGD system by reducing the variability of sulfur loading in the inlet flue gas. Coal blending may also be useful in reducing short-term peak SO_2 concentrations where ambient SO_2 levels are a problem.

Several comments were concerned with the dependability of FGD systems and problems encountered in operating them. The commenters suggested that FGD equipment is a high-risk investment, and there has been limited "successful" operating experience. They expressed the belief that utilities will experience increased maintenance requirements and that the possibility of forced outages due to scaling and corrosion would be greater as a result of the standards.

One commenter took issue with a statement that exhaust stack liner problems can be solved by using more expensive materials. The commenter also argued that EPA has no data supporting the assumption that scrubbers have been demonstrated at or near 90 percent reliability with one spare module. The Administrator has considered these comments and has concluded that properly designed and operated FGD systems can perform

reliably. An FGD system is a chemical process which must be designed (1) to include materials that will withstand corrosive/erosive conditions, (2) with instruments to monitor process chemistry and (3) with spare capacity to allow for planned downtime for routine maintenance. As with any chemical process, a startup or shakedown period is required before steady, reliable operation can be achieved.

The Administrator has continued to follow the progress of the FGD systems cited in the supporting documents published in conjunction with the proposed regulations in September 1978. Availability of the FGD system at Kansas City Power and Light Company's LaCygne Unit No. 1 has steadily improved. No FGD-related forced outages were reported from September 1977 to September 1978. Availability from January to September 1978 averaged 93 percent. Outages reported were a result of boiler and turbine problems but not FGD system problems. LaCygne Unit No. 1 burns high-sulfur (5 percent) coal, uses one of the earlier FGD's installed in the U.S., and reduces SO_2 emissions by 80 percent with a limestone system at greater than 90 percent availability. Northern States Power Company's Sherburne Units Numbers 1 and 2 on the other hand operate on low-sulfur coal (0.8 percent). Sherburne No. 1, which began operating early in 1976, had 93 percent availability in both 1977 and 1978. Sherburne No. 2, which began operation in late 1976 had availabilities of 93 percent in 1977 and 94 percent in 1978. Both of these systems include spare modules to maintain these high availabilities.

Several comments were received expressing concern over the increased water use necessary to operate FGD systems at utilities located in arid regions. The Administrator believes that water availability is a factor that limits power plant siting but since an FGD system uses less than 10 percent of the water consumed at a power plant, FGD will not be the controlling factor in the siting of new utility plants.

A few commenters criticized EPA for not considering amendments to the Federal Water Pollution Control Act (now the Clean Water Act), the Resource Conservation and Recovery Act, or the Toxic Substances Control Act when analyzing the water pollution and solid waste impacts of FGD systems. To the extent possible, the Administrator believes that the impacts of these Acts have been taken into consideration in this rule-making. The economic impacts were estimated on the basis of requirements anticipated for power plants under these Acts.

Various comments were received regarding the SO_2 removal efficiency achievable with FGD technology. One comment from a major utility system stated that they agreed with the standards, as proposed. Many comments stated that technology for better than 90 percent SO_2 removal exists. One comment was received stating that 95 percent SO_2 removal should be required. The Administrator concludes that higher SO_2 removals are achievable for low-sulfur coal which was the basis of this comment. While 95 percent SO_2 removal may be obtainable on high-sulfur coals with dual alkali or regenerable FGD systems, long-term data to support this level are not available and the Administrator has concluded that the demand for dual alkali/regenerable systems would far exceed vendor capabilities. When the uncertainties of extrapolating performance from 90 to 95 percent for high-sulfur coal, or from 95 percent on low-sulfur coal to high-sulfur coal, were considered, the Administrator concluded that 95 percent SO_2 removal for lime/limestone based systems on high-sulfur coal could not be reasonably expected at this time.

Another comment stated that all FGD systems except lime and limestone were not demonstrated or not universally applicable. The proposed SO_2 standards were based upon the conclusion that they were achievable with a well designed, operated, and maintained FGD system. At the time of proposal, the Administrator believed that lime and limestone FGD systems would be the choice of most utilities in the near future but, in some instances, utilities would choose the more reactive dual alkali or regenerable systems. The use of additives such as magnesium oxides was not considered to be necessary for attainment of the standard, but could be used at the option of the utility. Available data show that greater than 90 percent SO_2 removal has been achieved at full scale U.S. facilities for short-term periods when high-sulfur coal is being combusted, and for long-term periods at facilities when low-sulfur coal is burned. In addition, greater than 90 percent SO_2 removal has been demonstrated over long-term operating periods at FGD facilities when operating on low- and medium-sulfur coals in Japan.

Other commenters questioned the exclusion of dry scrubbing techniques from consideration. Dry scrubbing was considered in EPA's background documents and was not excluded from consideration. Five commercial dry SO_2 control systems are currently on order; three for utility boilers (400-MW, 455-MW, and 550-MW) and two for industrial applications. The utility units are designed to achieve 50 to 85 percent reduction on a long-term average basis and are scheduled to commence operation in 1981-1982. The design basis for these units is to comply with applicable State emission limitations. In addition, dry SO_2 control systems for six other utility boilers are out for bid. However, no full scale dry scrubbers are presently in operation at utility plants so information available to EPA and presented in the background document dealt with prototype units. Pilot scale data and estimated costs of full-scale dry scrubbing systems offer promise of moderately high (70-85 percent) SO_2 removal at costs of three-fourths or less of a comparable lime or limestone FGD system. Dry control system and wet control system costs are approximately equal for a 2-percent-sulfur coal. With lower-sulfur coals, dry controls are particularly attractive, not only because they would be less costly than wet systems, but also because they are expected to require less maintenance and operating staff, have greater turndown capabilities, require less energy consumption for operation, and produce a dry solid waste material that can be more easily disposed of than wet scrubber sludge.

Tests done at the Hoot Lake Station (a 53-MW boiler) in Minnesota demonstrated the performance capability of a spray dryer-baghouse dry control system. The exhaust gas concentrations before the control systems were 800 ppm SO_2 and an average of 2 gr/acf particulate matter. With lime as the sorbent, the control system removed over 86 percent SO_2 and 99.96 percent particulate matter at a stoichiometric ratio of 2.1 moles of lime absorbent per inlet mole of SO_2. When the spent lime dust was recirculated from the bag filter to the lime slurry feed tank, SO_2 removal efficiencies up to 90 percent ware obtained at stoichiometric ratios of 1.3-1.5. With the lime recirculation process, SO_2 removal efficiencies of 70-80 percent were demonstrated at a more economical stoichiometric ratio (about 0.75). Similar tests were performed at the Leland Olds Station using commercial grade lime.

Based upon the available information, the Administrator has concluded that 70 percent SO_2 removal using lime as the reactant is technically feasible and economically attractive in comparison to wet scrubbing when coals containing less than 1.5 percent sulfur are being

combusted. The coal reserves which contain 1.5 percent sulfur or less represent approximately 90 percent of the total Western U.S. reserves.

The standards specify a percentage reduction and an emission limit but do not specify technologies which must be used. The Administrator specifically took into consideration the potential of dry SO_2 scrubbing techniques when specifying the final form of the standard in order to provide an opportunity for their development on low-sulfur coals.

Averaging Time

Compiance with the final SO_2 standards is based on a 30-day rolling average. Compliance with the proposed standards was based on a 24-hour average.

Several comments state that the proposed SO_2 percent reduction requirement is attainable using currently available control equipment. One utility company commented upon their experience with operating pilot and prototype scrubbers and a full-scale limestone FGD system on a 550-MW plant. They stated that the FGD state of the art is sufficiently developed to support the proposed standards. Based on their analysis of scrubber operating variability and coal quality variability, they indicated that to achieve an 85 percent reduction in SO_2 emissions 90 percent of the time on a daily basis, the 30-day average scrubber efficiency would have to be at least 88 to 90 percent.

Other comments stated that EPA contractors did not consider SO_2 removal in context with averaging time, that vendor guarantees were not based on specific averaging times, and that quoted SO_2 removal efficiencies were based on testing modules. EPA found through a survey of vendors that many would offer 90–95 percent SO_2 removal guarantees based upon their usual acceptance test criteria. However, the averaging time was not specified. The Industrial Gas Cleaning Institute (IGCI), which represents control equipment vendors, commented that the control equipment industry has the present capability to design, manufacture, and install FGD control systems that have the capability of attaining the proposed SO_2 standards (a continuous 24-hour average basis). Concern was expressed, however, about the proposed 24-hour averaging requirement, and this commenter recommended the adoption of 30-day averaging. Since minute-to-minute variations in factors affecting FGD efficiency cannot be compensated for instantaneously, 24-hour averaging is an impracticably short period for implementing effective correction or for creating offsetting favorable higher efficiency periods.

Numerous other comments were received recommending that the proposed 24-hour averaging period be changed to 30 days. A utility company stated that their experience with operating full scale FGD systems at 500- and 400-MW stations indicates that variations in FGD operation make it extremely difficult, if not impossible, to maintain SO_2 removal efficiencies in compliance with the proposed percent reduction on a continual daily basis. A commenter representing the industry stated that it is clear from EPA's data that the averaging time could be no shorter than 24 hours, but that neither they nor EPA have data at this time to permit a reasonable determination of what the appropriate averaging time should be.

The Administrator has thoroughly reviewed the available data on FGD performance and all of the comments received. Based on this review, he has concluded that to alleviate this concern over coal sulfur variability, particularly its effect on small plant operations, and to allow greater flexibility in operating FGD units, the final SO_2 standard should be based on a 30-day rolling average rather than a 24-hour average as proposed. A rolling average has been adopted because it allows the Administrator to enforce the standard on a daily basis. A 30-day average is used because it better describes the typical performance of an FGD system, allows adequate time for owners or operators to respond to operating problems affecting FGD efficiency, permits greater flexibility in procedures necessary to operate FGD systems in compliance with the standard, and can reduce the effects of coal sulfur variability on maintaining compliance with the final SO_2 standards without the application of coal blending systems. Coal blending systems may be required in some cases, however, to provide for the attainment and maintenance of the National Ambient Air Quality Standards for SO_2.

Emission Limitation

In the September proposal, a 520 ng/J (1.20 lb/million Btu) heat input emission limit, except for 3 days per month, was specified for solid fuels. Compliance was to be determined on a 24-hour averaging basis.

Following the September proposal, the joint working group comprised of EPA, The Department of Energy, the Council of Economic Advisors, the Council on Wage and Price Stability, and others investigated ceilings lower than the proposal. In looking at these alternatives, the intent was to take full advantage of the cost effectiveness benefits of a joint coal washing/scrubbing strategy on high-sulfur coal. The cost of washing is relatively inexpensive; therefore, the group anticipated that a low emission ceiling, which would require coal washing and 90 percent scrubbing, could substantially reduce emissions in the East and Midwest at a relatively low cost. Since coal washing is now a widespread practice, it was thought that Eastern coal production would not be seriously impacted by the lower emission limit. Analyses using an econometric model of the utility sector confirmed these conclusions and the results were published in the **Federal Register** on December 8, 1978 (43 FR 57834).

Recognizing certain inherent limitations in the model when assessing impacts at disaggregated levels, the Administrator undertook a more detailed analysis of regional coal production impacts in February using Bureau of Mines reports which provided seam-by-seam data on the sulfur content of coal reserves and the coal washing potential of those reserves. The analysis identified the amount of reserves that would require more than 90 percent scrubbing of washed coal in order to meet designated ceilings. To determine the sulfur reduction from coal washing, the Administrator assumed two levels of coal preparation technology, which were thought to represent state-of-the-art coal preparation (crushing to 1.5-inch top size with separation at 1.6 specific gravity, and ⅜-inch top size with separation at 1.6 specific gravity). The amount of sulfur reduction was determined according to chemical characteristics of coals in the reserve base. This assessment was made using a model developed by EPA's Office of Research and Development.

As a result of concerns expressed by the National Coal Association, a meeting was called for April 5, 1979, in order for EPA and the National Coal Association to present their respective findings as they pertained to potential impacts of lower emission limits on high-sulfur coal reserves in the Eastern Midwest (Illinois, Indiana, and Western Kentucky) and the Northern Appalachian (Ohio, West Virginia, and Pennsylvania) coal regions. Recognizing the importance of discussion, the Administrator invited representatives from the Sierra Club, the Natural Resources Defense Council, the Environmental Defense Fund, the Utility

Air Regulatory Group, and the United Mine Workers of America, as well as other interested parties to attend.

At the April 5 meeting, EPA presented its analysis of the Eastern Midwest and Northern Appalachian coal regions. The analysis showed that at a 240 ng/J (0.55 lb/million Btu) annual emission limit more than 90 percent scrubbing would be required on between 5 and 10 percent of Northern Appalachian reserves and on 12 to 25 percent of the Eastern Midwest reserves. At a 340 ng/J (0.80 lb/million Btu) limit, less than 5 percent of the reserves in each of these regions would require greater than 90 percent scrubbing. At that same meeting, the National Coal Association presented data on the sulfur content and washability of reserves which are currently held by member companies. While the reported National Coal Association reserves represent a very small portion of the total reserve base, they indicate reserves which are planned to be developed in the near future and provide a detailed property-by-property data base with which to compare EPA analytical results. Despite the differences in data base sizes, the National Coal Association's study served to confirm the results of the EPA analysis. Since the National Coal Association results were within 5 percentage points of EPA's estimates, the Administrator concluded that the Office of Research and Development model would provide a widely accepted basis for studying coal reserve impacts. In addition, as a result of discussions at this meeting the Administrator revised his assessment of state-of-the-art coal cleaning technology. The National Coal Association acknowledged that crushing to 1.5-inch top size with separation at 1.6 specific gravity was common practice in industry, but that crushing to smaller top sizes would create unmanageable coal handling problems and great expense.

In order to explore further the potential for dislocations in regional coal markets, the Administrator concluded that actual buying practices of utilities rather than the mere technical usability of coals should be considered. This additional analysis identified coals that might not be used because of conservative utility attitudes toward scrubbing and the degree of risk that a utility would be willing to take in buying coal to meet the emission limit. This analysis was performed in a similar manner to the analysis described above except that two additional assumptions were made: (1) utilities would purchase coal that would provide about a 10 percent margin below the emission limit in order to minimize risk, and (2) utilities would purchase coal that would meet the emission limit (with margin) with a 90 percent reduction in potential SO_2 emissions. This assumption reflects utility preference for buying washed coal for which only 85 percent scrubbing is needed to meet both the percent reduction and the emission limit as compared to the previous assumption that utilities would do 90 percent scrubbing on washed coal (resulting in more than 90 percent reduction in potential SO_2 emissions). This analysis was performed using EPA data at 430 ng/J (1.0 lb/million Btu) and 520 ng/J (1.20 lb/million Btu) monthly emission limits. The results revealed that a significant portion (up to 22 percent) of the high-sulfur coal reserves in the Eastern Midwest and portions of Northern Appalachian coal regions would require more than a 90 percent reduction if the emission limitation was established below 520 ng/J (1.20 lb/million Btu) on a 30-day rolling average basis. Although higher levels of control are technically feasible, conservatism in utility perceptions of scrubber performance could create a significant disincentive against the use of these coals and disrupt the coal markets in these regions. Accordingly, the Administrator concluded the emission limitation should be maintained at 520 ng/J (1.20 lb/million Btu) on a 30-day rolling average basis. A more stringent emission limit would be counter to one of the basic purposes of the 1977 Amendments, that is, encouraging the use of higher sulfur coals.

Full Versus Partial Control

In September 1978, the Administrator proposed a full or uniform control alternative and set forth other partial or variable control options as well for public comment. At that time, the Administrator made it clear that a decision as to the form of the final standard would not be made until the public comments were evaluated and additional analyses were completed. The analytical results are discussed later under Regulatory Analysis.

This issue focuses on whether power plants firing lower-sulfur coals should be required to achieve the same percentage reduction in potential SO_2 emissions as those burning higher-sulfur coals. When addressing this issue, the public commenters relied heavily on the statutory language and legislative history of Section 111 of the Clean Air Act Amendments of 1977 to bolster their arguments. Particular attention was directed to the Conference Report which says in the pertinent part:

> In establishing a national percent reduction for new fossil fuel-fired sources, the conferees agreed that the Administrator may, in his discretion, set a range of pollutant reduction that reflects varying fuel characteristics. Any departure from the uniform national percentage reduction requirement, however, must be accompanied by a finding that such a departure does not undermine the basic purposes of the House provision and other provisions of the act, such as maximizing the use of locally available fuels.

Comments Favoring Full or Uniform Control. Commenters in favor of full control relied heavily on the statutory presumption in favor of a uniform application of the percentage reduction requirement. They argued that the Conference Report language, ". . . the Administrator may, in his discretion, set a range of pollutant reduction that reflects varying fuel characteristics. . . ." merely reflects the contention of certain conferees that low-sulfur coals may be more difficult to treat than high-sulfur coals. This contention, they assert, is not borne out by EPA's technical documentation nor by utility applications for prevention of significant deterioration permits which clearly show that high removal efficiencies can be attained on low-sulfur coals. In the face of this, they maintain there is no basis for applying a lower percent reduction for such coals.

These commenters further maintain that a uniform application of the percent reduction requirement is needed to protect pristine areas and national parks, particularly in the West. In doing so, they note that emissions may be up to seven times higher at the individual plant level under a partial approach than under uniform control. In the face of this, they maintain that partial control cannot be considered to reflect best available control technology. They also contend that the adoption of a partial approach may serve to undermine the more stringent State requirements currently in place in the West.

Turning to national impacts, commenters favoring a uniform approach note that it will result in lower emissions. They maintain that these lower emissions are significant in terms of public health and that such reductions should be maximized, particularly in light of the Nation's commitment to greater coal use. They also assert that a uniform standard is clearly affordable. They point out that the incremental increase in costs associated with a uniform standard is small when compared to total utility expenditures and will have a minimal impact at the consumer level. They further maintain that EPA has inflated

the costs of scrubber technology and has failed to consider factors that should result in lower costs in future years.

With respect to the oil impacts associated with a uniform standard, these same commenters are critical of the oil prices used in the EPA analyses and add that if a higher oil price had been assumed the supposed oil impact would not have materialized.

They also maintain that the adoption of a partial approach would serve to perpetuate the advantage that areas producing low-sulfur coal enjoyed under the current standard, which would be counter to one of the basic purposes of the House bill. On the other hand, they argue, a uniform standard would not only reduce the movement of low-sulfur coals eastward but would serve to maximize the use of local high-sulfur coals.

Finally, one of the commenters specified a more stringent full control option than had been analyzed by EPA. It called for a 95 percent reduction in potential SO_2 emissions with about a 280 ng/J (0.65 lb/million Btu) emission limit on a monthly basis. In addition, this alternative reflected higher oil prices and declining scrubber costs with time. The results were presented at the December 12 and 13 public hearing on the proposed standards.

Comments Favoring Partial or Variable Control. Those commenters advocating a partial or variable approach focused their arguments on the statutory language of Section 111. They maintained that the standard must be based on the "best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." They also asserted that the Conference Report language clearly gives the Administrator authority to establish a variable standard based on varying fuel characteristics, i.e., coal sulfur content.

Their principal argument is that a variable approach would achieve virtually the same emission reductions at the national level as a uniform approach but at substantially lower costs and without incurring a significant oil penalty. In view of this, they maintain that a variable approach best satisfies the statutory language of Section 111.

In support of variable control they also note that the revised NSPS will serve as a minimum requirement for prevention of significant deterioration and non-attainment considerations, and that ample authority exists to impose more stringent requirements on a case-by-case basis. They contend that these authorities should be sufficient to protect pristine areas and national parks in the West and to assure the attainment and maintenance of the health-related ambient air quality standards. Finally, they note that the NSPS is technology-based and not directly related to protection of the Nation's public health.

In addition, they argue that a variable control option would provide a better opportunity for the development of innovative technologies. Several commenters noted that, in particular, a uniform requirement would not provide an opportunity for the development of dry SO_2 control systems which they felt held considerable promise for bringing about SO_2 emission reductions at lower costs and in a more reliable manner.

Commenters favoring variable control also advanced the arguments that a standard based on a range of percent reductions would provide needed flexibility, particularly when selecting intermediate sulfur content coals. Further, if a control system failed to meet design expectations, a variable approach would allow a source to move to lower-sulfur coal to achieve compliance. In addition, for low-sulfur coal applications, a variable option would substantially reduce the energy penalty of operating wet scrubbers since a portion of the flue gas could be used for plume reheat.

To support their advocacy of a variable approach, two commenters, the Department of Energy and the Utility Air Regulatory Group (UARG, representing a number of utilities), presented detailed results of analyses that had been conducted for them. UARG analyzed a standard that required a minimum reduction of 20 percent with 520 ng/J (1.20 lb/million Btu) monthly emission limit. The Department of Energy specified a partial control option that required a 33 percent minimum requirement with a 430 ng/J (1.0 lb/million Btu) monthly emission limit.

Faced with these comments, the Administrator determined the final analyses that should be performed. He concluded that analyses should be conducted on a range of alternative emission limits and percent reduction requirements in order to determine the approach which best satisfies the statutory language and legislative history of section 111. For these analyses, the Administrator specified a uniform or full control option, a partial control option reflecting the Department of Energy's recommendation for a 33 percent minimum control requirement, and a variable control option which specified a 520 ng/J (1.20 lb/million Btu) emission limitation with a 90 percent reduction in potential SO_2 emissions except when emissions to the atmosphere were reduced below 260 ng/J (0.60 lb/million Btu), when only a 70 percent reduction in potential SO_2 emissions would apply. Under the variable approach, plants firing high-sulfur coals would be required to achieve a 90 percent reduction in potential emissions in order to comply with the emission limitation. Those using intermediate and low-sulfur content coals would be permitted to achieve between 70 and 90 percent, provided their emissions were less than 260 ng/J (0.60 lb/million BTU).

In rejecting the minimum requirement of 20 percent advocated by UARG, the Administrator found that it not only resulted in the highest emissions, but that it was also the least cost effective of the variable control options considered. The more stringent full control option presented in the comments was rejected because it required a 95 percent reduction in potential emissions which may not be within the capabilities of demonstrated technology for high-sulfur coals in all cases.

Emergency Conditions

The final standards allow an owner or operator to bypass uncontrolled flue gases around a malfunctioning FGD system provided (1) the FGD system has been constructed with a spare FGD module, (2) FGD modules are not available in sufficent numbers to treat the entire quantity of flue gas generated, and (3) all available electric generating capacity is being utilized in a power pool or network consisting of the generating capacity of the affected utility company (except for the capacity of the largest single generating unit in the company), and the amount of power that could be purchased from neighboring interconnected utility companies. The final standards are essentially the same as those proposed. The revisions involve wording changes to clarify the Administrator's intent and revisions to address potential load management and operating problems. None of the comments received by EPA disputed the need for the emergency condition provisions or objected to their intent.

The intent of the final standards is to encourage power plant owners and operators to install the best available FGD systems and to implement effective

operation and maintenance procedures but not to create power supply disruptions. FGD systems with spare FGD modules and FGD modules with spare equipment components have greater capability of reliable operation than systems without spares. Effective control and operation of FGD systems by engineering supervisory personnel experienced in chemical process operations and properly trained FGD system operators and maintenance staff are also important in attaining reliable FGD system operation. While the standards do not require these equipment and staffing features, the Administrator believes that their use will make compliance with the standards easier. Malfunctioning FGD systems are not exempt from the SO_2 standards except during infrequent power supply emergency periods. Since the exemption does not apply unless a spare module has been installed (and operated), a spare module is required for the exemption to apply. Because of the disproportionate cost of installing a spare module on steam generators having a generating capacity of 125 MW or less, the standards do not require them to have spare modules before the emergency conditions exemption applies.

The proposed standards included the requirement that the emergency condition exemption apply only to those facilities which have installed a spare FGD system module or which have 125 MW or less of output capacity. However, they did not contain procedures for demonstrating spare module capability. This capability can be easily determined once the facility commences operation. To specify how this determination is to be performed, provisions have been added to the regulations. This determination is not required unless the owner or operator of the affected facility wishes to claim spare module capability for the purpose of availing himself of the emergency condition exemption. Should the Administrator require a demonstration of spare module capability, the owner or operator would schedule a test within 60 days for any period of operation lasting from 24 hours to 30 days to demonstrate that he can attain the appropriate SO_2 emission control requirements when the facility is operated at a maximum rate without using one of its FGD system modules. The test can start at any time of day and modules may be rotated in and out of service, but at all times in the test period one module (but not necessarily the same module) must not be operated to demonstrate spare module capability.

Although it is within the Administrator's discretion to require the spare module capability demonstration test, the owner or operator of the facility has the option to schedule the specific date and duration of the test. A minimum of only 24 hours of operation are required during the test period because this period of time is adequate to demonstrate spare module capability and it may be unreasonable in all circumstances to require a longer (e.g., 30 days) period of operation at the facility's maximum heat input rate. Because the owner or operator has the flexibility to schedule the test, 24 hours of operation at maximum rate will not impose a significant burden on the facility

The Administrator believes that the standards will not cause supply disruption because (1) well designed and operated FGD systems can attain high operating availability, (2) a spare FGD module can be used to rotate other modules out of service for periodic maintenance or to replace a malfunctioning module, (3) load shifting of electric generation to another generating unit can normally be used if a part or all of the FGD system were to malfunction, and (4) during abnormal power supply emergency periods, the bypassing exemption ensures that the regulations would not require a unit to stand idle if its operation were needed to protect the reliability of electric service. The Administrator believes that this exemption will not result in extensive bypassing because the probability of a major FGD malfunction and power supply emergency occurring simultaneously is small.

A commenter asked that the definition of system capacity be revised to ensure that the plant's capability rather than plant rated capacity be used because the full rated capacity is not always operable. The Administrator agrees with this comment because a component failure (e.g., the failure of one coal pulverizer) could prevent a boiler from being operated at its rated capacity, but would not cause the unit to be entirely shut down. The definition has been revised to allow use of the plant's capability when determining the net system capacity.

One commenter asked that the definition of system capacity be revised to include firm contractual purchases and to exclude firm contractual sales. Because power obtained through contractual purchases helps to satisfy load demand and power sold under contract affects the net electric generating capacity available in the system, the Administrator agrees with this request and has included power purchases in the definition of net system capacity and has excluded sales by adding them to the definition of system load.

A commenter asked that the ownership basis for proration of electric capacity in several definitions be modified when there are other contractual arrangements. The Administrator agrees with this comment and has revised the definitions accordingly.

One commenter asked that definitions describing "all electric generating equipment owned by the utility company" specifically include hydroelectric plants. The proposed definitions did include these plants, but the Administrator agrees with the clarification requested, and the definitions have been revised.

A commenter asked that the word "steam" be removed from the definition of system emergency reserves to clarify that nuclear units are included. The Administrator agrees with the comment and has revised the definition.

Several commenters asked that some type of modification be made to the emergency condition provisions that would consider projected system load increases within the next calendar day. One commenter asked that emergency conditions apply based on a projection of the next day's load. The Administrator does not agree with the suggestion of using a projected load, which may or may not materialize, as a criterion to allow bypassing of SO_2 emissions, because the load on a generating unit with a malfunctioning FGD system should be reduced whenever there is other available system capacity.

A commenter recommended that a unit removed from service be allowed to return to service if such action were necessary to maintain or reestablish system emergency reserves. The Administrator agrees that it would be impractical to take a large steam generating unit entirely out of service whenever load demand is expected to later increase to the level where there would be no other unit available to meet the demand or to maintain system emergency reserves. To address the problem of reducing load and later returning the load to the unit, the Administrator has revised the proposed emergency condition provisions to give an owner or operator of a unit with a malfunctioning FGD system the option of keeping (or bringing) the unit into spinning reserve when the unit is needed to maintain (or reestablish) system emergency reserves. During this

period, emissions must be controlled to the extent that capability exists within the FGD system, but bypassing emissions would be allowed when the capability of a partially or completely failed FGD system is inadequate. This procedure will allow the unit to operate in spinning reserve rather than being entirely shut down and will ensure that a unit can be quickly restored to service. The final emergency condition provisions permit bypassing of emissions from a unit kept in spinning reserve, but only (1) when the unit is the last one available for maintaining system emergency reserves, (2) when it is operated at the minimum load consistent with keeping the unit in spinning reserve, and (3) has inadequate operational FGD capability at the minimum load to completely control SO_2 emissions. This revision will still normally require load on a malfunctioning unit to be reduced to a minimum level, even if load demand is anticipated to increase later; but it does prevent having to take the unit entirely out of operation and keep it available in spinning reserve to assume load should an emergency arise or as load increases the following day. Because emergency condition periods are a small percentage of total operating hours, this revision to allow bypassing of SO_2 emissions from a unit held in spinning reserve with reduced output is expected to have minor impact on the amount of SO_2 emitted.

One commenter stated that the proposed provisions would not reduce the necessity for additional plant capacity to compensate for lower net reliability. The Administrator does not agree with this comment because the emergency condition provisions allow operation of a unit with a failed FGD system whenever no other generating capacity is available for operation and thereby protects the reliability of electric service. When electric load is shifted from a new steam-electric generating unit to another electric generating unit, there would be no net change in reserves within the power system. Thus, the emergency condition provisions prevent a failed FGD system from impacting upon the utility company's ability to generate electric power and prevents an impact upon reserves needed by the power system to maintain reliable electric service.

A commenter asked that the definition of available system capacity be clarified because (1) some utilities have certain localized areas or zones that, because of system operating parameters, cannot be served by all of the electric generating units which constitute the utility's system capacity, and (2) an affected facility may be the only source of supply for a zone or area. Almost all electric utility generating units in the United States are electrically interconnected through power transmission lines and switching stations. A few isolated units in the U.S. are not interconnected to at least one other electric generating unit and it is possible that a new unit could also be constructed in an isolated area where interconnections would not be practical. For a single, isolated unit where it is not practical to construct interconnections, the emergency condition provisions would apply whenever an FGD malfunction occurred because there would be no other available system capacity to which load could be shifted. It is also possible that two or three units could be interconnected, but not interconnected with a larger power network (e.g., Alaska and Hawaii). To clarify this situation, the definitions of net system capacity, system load, and system emergency reserves have been revised to include only that electric power or capacity interconnected by a network of power transmission facilities. Few units will not be interconnected into a network encompassing the principal and neighboring utility companies. Power plants, including those without FGD systems, are expected to experience electric generating malfunctions and power systems are planned with reserve generating capacity and interconnecting electric transmission lines to provide means of obtaining electricity from alternative generating facilities to meet demand when these occasions arise. Arrangements for an affected facility would typically include an interconnection to a power transmission network even when it is geographically located away from the bulk of the utility company's power system to allow purchase of power from a neighboring utility for those localized service areas when necessary to maintain service reliability. Contract arrangements can provide for trades of power in which a localized zone served by the principal company owning or operating the affected facility is supplied by a neighboring company. The power bought by the principal company can, if desired by the neighboring company, be replaced by operation of other available units in the principal company even if these units are located at a distance from the localized service zone. The proposed definition of emergency condition was contingent upon the purchase of power from another electrical generation facility. To further clarify this relationship, the Administrator has revised the proposed definitions to define the relationship between the principal company (the utility company that owns the generating unit with the malfunctioning FGD system) and the neighboring power companies for the purpose of determining when emergency conditions exist.

A commenter requested that the proposed compliance provisions be revised so that they could not be interpreted to force a utility to operate a partially functional FGD module when extensive damage to the FGD module would occur. For example, a severely vibrating fan must be shut down to prevent damage even though the FGD system may be otherwise functional. The Administrator agrees with this comment and has revised the compliance provisions not to require FGD operation when significant damage to equipment would result.

One commenter asked that the definition of system emergency reserves account for not only the capacity of the single largest generating unit, but also for reserves needed for system load-frequency regulation. Regulation of power frequency can be a problem when the mix of capacitive and reactive loads shift. For example, at night capacitive load of industrial plants can adversely affect power factors. The Administrator disagrees that additional capacity should be kept independent of the load shifting requirements. Under the definition for system emergency reserves, capacity equivalent to the largest single unit in the system was set aside for load management. If frequency regulation has been a particular problem, extra reserve margins would have been maintained by the utility company even if an FGD system were not installed. Reserve capacity need not be maintained within a single generating unit. The utility company can regulate system load-frequency by distributing their system reserves throughout the electric power system as needed. In the Administrator's judgment, these regulations do not impact upon the reserves maintained by the utility company for the purpose of maintaining power system integrity, because the emergency condition provisions do not restrict the utility company's freedom in distributing their reserves and do not require construction of additional reserves.

A commenter asked that utility operators be given the option to ignore the loss of SO_2 removal efficiency due to FGD malfunctions by reducing the level of electric generation from an affected unit. This would control the amount of

SO_2 emitted on a pounds per hour basis, but would also allow and exemption from the percentage of SO_2 removal specified by the SO_2 standards. The Administrator believes that allowing this exemption is not necessary because load can usually be shifted to other electric generating units. This procedure provides an incentive to the owner or operator to properly maintain and operate FGD systems. Under the procedures suggested by the commenter, neglect of the FGD system would be encouraged because an exemption would allow routine operation at reduced percentages of SO_2 removal. Steam generating units are often operated at less than rated capacity and a fully operational FGD system would not be required for compliance during these periods if this exemption were allowed. The procedure suggested by the commenter is also not necessary because FGD modules can be designed and constructed with separate equipment components so that they are routinely capable of independent operation whenever another module of the steam generating unit's FGD system is not available. Thus, reducing the level of electric generation and removing the failed FGD module for servicing would not affect the remainder of the FGD system and would permit the utility to maintain compliance with the standards without having to take the generating unit entirely out of operation. Each module should have the capability of attaining the same percentage reduction of SO_2 from the flue gas it treats regardless of the operability of the other modules in the system to maintain compliance with the standards. Although the efficiency of more than one FGD module may occasionally be affected by certain equipment malfunctions, a properly designed FGD system has no routine need for an exemption from the SO_2 percentage reduction requirement when the unit is operated at reduced load. The Administrator has concluded that the final regulations provide sufficient flexibility for addressing FGD malfunctions and that an exemption from the percentage SO_2 removal requirement is not necessary to protect electric service reliability or to maintain compliance with these SO_2 standards.

Particulate Matter Standard

The final standard limits particulate matter emissions to 13 ng/J (0.03 lb/million Btu) heat input and is based on the application of ESP or baghouse control technology. The final standard is the same as the proposed. The Administrator has concluded that ESP and baghouse control systems are the best demonstrated systems of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, and nonair quality health and enviornmental impacts, and energy requirements) and that 13 ng/J (0.03 lb/million Btu) heat input represents the emission level achievable through the application of these control systems.

One group of commenters indicated that they did not support the proposed standard because in their opinion it would be too expensive for the benefits obtained; and they suggested that the final standard limit emissions to 43 ng/J (0.10 lb/million Btu) heat input which is the same as the current standard under 40 CFR Part 60 Subpart D. The Administrator disagrees with the commenters because the available data clearly indicate that ESP and baghouse control systems are capable of performing at the 13 ng/J (0.03 lb/million Btu) heat input emission level, and the economic impact evaluation indicates that the costs and economic impacts of installing these systems are reasonable.

The number of commenters expressed the opinion that the proposed standard was to strict, particularly for power plants firing low-sulfur coal, because baghouse control systems have not been adequately demonstrated on full-size power plants. The commenters suggested that extrapolation of test data from small scale baghhouse control systems, such as those used to support the proposed standard, to full-size utility applications is not reasonable.

The Administrator believes that baghouse control systems are demonstrated for all sizes of power plants. At the time the standards were proposed, the Administrator concluded that since baghouses are designed and constructed in modules rather than as one large unit, there should be no technological barriers to designing and constructing utility-sized facilities. The largest baghouse-controlled, coal-fired power plant for which EPA had emission test data to support the proposed standard was 44 MW. Since the standards were proposed, additional information has become available which supports the Administrator's position that baghouses are demonstrated for all sizes of power plants. Two large baghouse-controlled, coal-fired power plants have recently initiated operations. EPA has obtained emission data for one of these units. This unit has achieved particulate matter emission levels below 13 ng/J (0.03 lb/million Btu) heat input. The baghouse system for this facility has 28 modules rated at 12.5 MW capacity per module. This supports the Administrator's conclusion that baghouses are designed and constructed in modules rather than as one large unit, and there should be no technological barriers to designing and constructing utility-sized facilities.

One commenter indicated that baghouse control systems are not demonstrated for large utility application at this time and recommended that EPA gather one year of data from 1000 MW of baghouse installations to demonstrate that baghouses can operate reliably and achieve 13 ng/J (0.03 lb/million Btu) heat input. The standard would remain at 21 to 34 ng/J (0.05 to 0.08 lb/million Btu) heat input until such demonstration. The Administrator does not believe this approach is necessary because baghouse control systems have been adequately demonstrated for large utility applications.

One group of commenters supported the proposed standard of 13 ng/J (0.03 lb/million Btu) heat input. They indicated that in their opinion the proposed standard attained the proper balance of cost, energy and environmental factors and was necessary in consideration of expected growth in coal-fired power plant capacity.

Another group of commenters which included the trade association of emission control system manufacturers indicated that 13 ng/J (0.03 lb/million Btu) is technically achievable. The trade association further indicated the proposed standard is technically achievable for either high- or low-sulfur coals, through the use of baghouses, ESPs, or wet scrubbers.

A number of commenters recommended that the proposed standard be lowered to 4 ng/J (0.01 lb/million Btu) heat input. This group of commenters presented additional emission data for utility baghouse control systems to support their recommendation. The data submitted by the commenters were not available at the time of proposal and were for utility units of less than 100 MW electrical output capacity. The commenters suggested that a 4 ng/J (0.01 lb/million Btu) heat input standard is achievable based on baghouse technology, and they suggested that a standard based on baghouse technology would be consistent with the technology-forcing nature of section 111 of the Act. The Administrator believes that the available data base for baghouse performance supports a standard of 13 ng/J (0.03 lb/million Btu) heat input but

does not support a lower standard such as 4 ng/J (0.01 lb/million Btu) heat input.

One commenter suggested that the standard should be set at 26 ng/J (0.06 lb/million Btu) heat imput so that particulate matter control systems would not be necessary for oil-fired utility steam generators. Although it is expected that few oil-fired utility boilers will be constructed, the ESP performance data which is contained in the "Electric Utility Steam Generating Units, Background Information for Promulgated Emission Standards" (EPA 450/3-79-021), supports the conclusion that ESPs are applicable to both oil firing and coal firing. The Administrator believes that emissions from oil-fired utility boilers should be controlled to the same level as coal-fired boilers.

NO_x Standard

The NO_x standards limit emissions to 210 ng/J (0.50 lb/million Btu) heat input from the combustion of subbituminous coal and 260 ng/J (0.60 lb/million Btu) heat imput from the combustion of bituminous coal, based on a 30-day rolling average. In addition, emission limits have been established for other solid, liquid, and gaseous fuels, as discussed in the rational section of this preamble. The final standards differ from the proposed standards only in that the final averaging time for determining compliance with the standards is based on a 30-day rolling average, whereas a 24-hour average was proposed. All comments received during the public comment period were considered in developing the final NO_x standards. The major issues raised during the comment period are discussed below.

One issue concerned the possibility that the proposed 24-hour averaging period for coal might seriously restrict the flexibility boiler operators need during day-to-day operation. For example, several commenters noted that on some boilers the control of boiler tube slagging may periodically require increased excess air levels, which, in turn, would increase NO_x emissions. One commenter submitted data indicating that two modern Combustion Engineering (CE) boilers at the Colstrip, Montana plant of the Montana Power Company do not consistently achieve the proposed NO_x level of 210 ng/J (0.50 lb/million Btu) heat input on a 24-hour basis. The Colstrip boilers burn subbituminous coal and are required to comply with the NO_x standard under 40 CFR Part 60, Subpart D of 300 ng/J (0.70 lb/million Btu) heat input. Several other commenters recommended that the 24-hour averaging period be extended to 30 days to allow for greater operational flexibility.

As an aid in evaluating the operational flexibility question, the Administrator has reviewed a total of 24 months of continuously monitored NO_x data from the two Colstrip boilers. Six months of these data were available to the Administrator before proposal of these standards, and two months were submitted by a commenter. The commenter also submitted a summary of 28 months of Colstrip data indicating the number of 24-hour averages per month above 210 ng/J (0.50 lb/million Btu) heat input. The remaining Colstrip data were obtained by the Administrator from the State of Montana after proposal. In addition to the Colstrip data, the Administrator has reviewed approximately 10 months of continuously monitored NO_x data from five modern CE utility boilers. Three of the boilers burn subbituminous coal, two burn bituminous coal, and all five have monitors that have passed certification tests. These data were obtained from electric utility companies after proposal. A summary of all of the continuously monitored NO_x data that the Administrator has considered appears in "Electric Utility Steam Generating Units, Background Information for Promulgated Emission Standards" (EPA 450/3-79-021).

The usefulness of these continuously monitored data in evaluating the ability of modern utility boilers to continuously achieve the NO_x emission limits of 210 and 260 ng/J (0.50 and 0.60 lb/million Btu) heat input is somewhat limited. This is because the boilers were required to comply with a higher NO_x level of 300 ng/J (0.70 lb/million Btu) heat input. Nevertheless some conclusions can be drawn, as follows:

(1) Nearly all of the continuously monitored NO_x data are in compliance with the boiler design limit of 300 ng/J (0.70 lb/million Btu) heat input on the basis of a 24-hour average.

(2) Most of the continuously monitored NO_x data would be in compliance with limits of 260 ng/J (0.60 lb/million Btu) heat input for bituminous coal ov 210 ng/J (0.50 lb/million Btu) heat input for subbituminous coal when averaged over a 30-day period. Some of the data would be out of compliance based on a 24-hour average.

(3) The volume of continuously monitored NO_x emission data evaluated by the Administrator (34 months from seven large coal-fired boilers) is sufficient to indicate the emission variability expected during day-to-day operation of a utility-size boiler. In the Administrator's judgment, this emission variability adequately represents slagging conditions, coal variability, load changes, and other factors that may influence the level of NO_x emissions.

(4) The variability of continuously monitored NO_x data is sufficient to cause some concern over the ability of a utility boiler that burns solid fuel to consistently achieve a NO_x boiler design limit, whether 300, 260, or 210 ng/J (0.70, 0.60, or 0.50 lb/million Btu) heat input, based on 24-hour averages. In contrast, it appears that there would be no difficulty in achieving the boiler design limit based on 30-day periods.

Based on these conclusions, the Administrator has decided to require compliance with the final standards for solid fuels to be based on a 30-day rolling average. The Administrator believes that the 30-day rolling average will allow boilers made by all four major boiler manufacturers to achieve the standards while giving boiler operators the flexibility needed to handle conditions encountered during normal operation.

Although the Administrator has not evaluated continuously monitored NO_x data from boilers manufactured by companies other than CE, the data from CE boilers are considered representative of the other boiler manufacturers. This is because the boilers of all four manufacturers are capable of achieving the same NO_x design limit, and because the conditions that occur during normal operation of a boiler (e.g., slagging, variations in fuel quality, and load reductions) are similar for all four manufacturer designs. These conditions, the Administrator believes, lead to similar emission variability and require essentially the same degree of operational flexibility.

Some commenters have question the validity of the Colstrip data because the Colstrip continuous NO_x monitors have not passed certification tests. In April and June of 1978 EPA conducted a detailed evaluation of these monitors. The evaluation led the Administrator to conclude that the monitors were probably biased high, but by less than 21 ng/J (0.50 lb/million Btu) heat input. Since this error is so small (less than 10 percent), the Administrator considers the data appropriate to use in developing the standards.

A number of commenters expressed concern over the ability of as many as three of the four major boiler manufacturer designs to achieve the proposed standards. Although most of the available NO_x test data are from CE boilers, the Administrator believes that all four of the boiler manufacturers will be able to supply boilers capable of

achieving the standards. This conclusion is supported with (1) emission test results from 14 CE, seven Babcock and Wilcox (B&W), three Foster Wheeler (FW), and four Riley Stoker (RS) utility boilers; (2) 34 months of continuously monitored NO_x emission data from seven CE boilers; and (3) an evaluation of plans under way at B&W, FW, and RS to develop low-emission burners and furnace designs. Full-scale tests of these burners and furnace designs have proven their effectiveness in reducing NO_x emissions without apparent long-term adverse side effects.

Another issue raised by commenters concerned the effect that variations in the nitrogen content of coal may have on achieving the NO_x standards. The Adminstrator recognizes that NO_x levels are sensitive to the nitrogen content of the coal burned and that the combustion of high-nitrogen-content coals might be expected to result in higher NO_x emissions than those from coals with low nitrogen contents. However, the Administrator also recognizes that other factors contribute to NO_x levels, including moisture in the coal, boiler design, and boiler operating practice. In the Administrator's judgment, the emission limits for NO_x are achievable with properly designed and operated boilers burning any coal, regardless of its nitrogen content. As evidence of this, three of the six boilers tested by EPA burned coals with nitrogen contents above average, and yet exhibited NO_x emission levels well below the standards. The three boilers that burned coals with lower nitrogen contents also exhibited emission levels below the standards. The Administrator believes this is evidence that at NO_x levels near 210 and 260 ng/J (0.50 and 0.60 lb/million Btu) heat input, factors other than fuel-nitrogen-content predominate in determining final emission levels.

A number of commenters expressed concern over the potential for accelerated tube wastage (i.e., corrosion) during operation of a boiler in compliance with the proposed standards. Almost all of the 300-hour and 30-day coupon corrosion tests conducted during the EPA-sponsored low-NO_x studies indicate that corrosion rates decrease or remain stable during operation of boilers at NO_x levels as low as those required by the standards. In the few instances where corrosion rates increased during low-NO_x operation, the increases were considered minor. Also, CE has guaranteed that its new boilers will achieve the NO_x emission limits without increased tube corrosion rates. Another boiler manufacturer, B&W, has developed new low-emission burners that minimize corrosion by surrounding the flame in an oxygen-rich atmosphere. The other boiler manufacturers have also developed techniques to reduce the potential for corrosion during low-NO_x operation. The Administrator has received no contrasting information to the effect that boiler tube corrosion rates would significantly increase as a result of compliance with the standards.

Several commenters stated that according to a survey of utility boilers subject to the 300 ng/J (0.70 lb/million Btu) heat input standard under 40 CFR Part 60, Subpart D, none of the boilers can achieve the standard promulgated here of 260 ng/J (0.60 lb/million Btu) heat input on a range of bituminous coals. Three of the six utility boilers tested by EPA burned bituminous coal. (Two of these boilers were manufactured by CE and one by B&W.) In addition, the Administrator has reviewed continuously monitored NO_x data from two CE boilers that burn bituminous coal. Finally, the Administrator has examined NO_x emission data obtained by the boiler manufacturers on seven CE, four B&W, three FW, and three RS modern boilers, all of which burn bituminous coal. Nearly all of these data are below the 260 ng/J (0.60 lb/million Btu) heat input standard. The Administrator believes that these data provide adequate evidence that the final NO_x standard for bituminous coal is achievable by all four boiler manufacturer designs.

An issue raised by several commenters concerned the use of catalytic ammonia injection and advanced low-emission burners to achieve NO_x emission levels as low as 15 ng/J (0.034 lb/million Btu) heat input. Since these controls are not yet available, the commenters recommended that new utility boilers be designed with sufficient space to allow for the installation of ammonia injection and advanced burners in the future. In the meantime the commenters recommended that NO_x emissions be limited to 190 ng/J (0.45 lb/million Btu) heat input. The Administrator believes that the technology needed to achieve NO_x levels as low as 15 ng/J (0.034 lb/million Btu) heat input has not been adequately demonstrated at this time. Although a pilot-scale catalytic-ammonia-injection system has successfully achieved 90 percent NO_x removal at a coal-fired utility power plant in Japan, operation of a full-scale ammonia-injection system has not yet been demonstrated on a large coal-fired boiler. Since the Clean Air Act requires that emission control technology for new source performance standards be adequately demonstrated, the Administrator cannot justify establishing a low NO_x standard based on unproven technology. Similarly, the Administrator cannot justify requiring boiler designs to provide for possible future installation of unproven technology.

The recommendation that NO_x emissions be limited to 190 ng/J (0.45 lb/million Btu) heat input is based on boiler manufacturer guarantees in California. (No such utility boilers have been built as yet.) Although manufacturer guarantees are appropriate to consider when establishing emission limits, they cannot always be used as a basis for a standard. As several commenters have noted, manufacturers do not always achieve their performance guarantees. The standard is not established at this level, because emission test data are not available which demonstrate that a level of 190 ng/J (0.45 lb/million Btu) heat input can be continuously achieved without adverse side effects when a wide variety of coals are burned.

Regulatory Analysis

Executive Order 12044 (March 24, 1978), whose objective is to improve Government regulations, requires executive branch agencies to prepare regulatory analyses for regulations that may have major economic consequences. EPA has extensively analyzed the costs and other impacts of these regulations. These analyses, which meet the criteria for preparation of a regulatory analysis, are contained within the preamble to the proposed regulations (43 FR 42154), the background documentation made available to the public at the time of proposal (see STUDIES, 43 FR 42171), this preamble, and the additional background information document accompanying this action ("Electric Utility Steam Generating Units, Background Information for Promulgated Emission Standards," EPA-450/3-79-021). Due to the volume of this material and its continual development over a period of 2-3 years, it is not practical to consolidate all analyses into a single document. The following discussion gives a summary of the most significant alternatives considered. The rationale for the action taken for each pollutant being regulated is given in a previous section.

In order to determine the appropriate form and level of control for the standards, EPA has performed extensive analysis of the potential national impacts associated with the alternative standards. EPA employed economic models to forecast the structure and

operating characteristics of the utility industry in future years. These models project the environmental, economic, and energy impacts of alternative standards for the electric utility industry. The major analytical efforts took place in three phases as described below.

Phase 1. The initial effort comprised a preliminary analysis completed in April 1978 and a revised assessment completed in August 1978. These analyses were presented in the September 19, 1978 **Federal Register** proposal (43 FR 42154). Corrections to the September proposal package and additional information was published on November 27, 1978 (43 FR 55258). Further details of the analyses can be found in "Background Information for Proposed SO_2 Emission Standards—Supplement," EPA 450/2-78-007a-1.

Phase 2. Following the September 19 proposal, the EPA staff conducted additional analysis of the economic, environmental, and energy impacts associated with various alternative sulfur dioxide standards. As part of this effort, the EPA staff met with representatives of the Department of Energy, Council of Economic Advisors, Council on Wage and Price Stability, and others for the purpose of reexamining the assumptions used for the August analysis and to develop alternative forms of the standard for analysis. As a result, certain assumptions were changed and a number of new regulatory alternatives were defined. The EPA staff again employed the economic model that was used in August to project the national and regional impacts associated with each alternative considered.

The results of the phase 2 analysis were presented and discussed at the public hearings in December and were published in the **Federal Register** on December 8, 1978 (43 FR 7834).

Phase 3. Following the public hearings, the EPA staff continued to analyze the impacts of alternative sulfur dioxide standards. There were two primary reasons for the continuing analysis. First, the detailed analysis (separate from the economic modeling) of regional coal production impacts pointed to a need to investigate a range of higher emission limits.

Secondly, several comments were received from the public regarding the potential of dry sulfur dioxide scrubbing systems. The phase 1 and phase 2 analyses had assumed that utilities would use wet scrubbers only. Since dry scrubbing costs substantially less then wet scrubbing, adoption of the dry technology would substantially change the economic, energy, and environmental impacts of alternative sulfur dioxide standards. Hence, the phase 3 analysis focused on the impacts of alternative standards under a range of emission ceilings assuming both wet technology and the adoption of dry scrubbing for applications in which it is technically and economically feasible.

Impacts Analyzed

The environmental impacts of the alternative standards were examined by projecting pollutant emissions. The emissions were estimated nationally and by geographic region for each plant type, fuel type, and age category. The EPA staff also evaluated the waste products that would be generated under alternative standards.

The economic and financial effects of the alternatives were examined. This assessment included an estimation of the utility capital expenditures for new plant and pollution control equipment as well as the fuel costs and operating and maintenance expenses associated with the plant and equipment. These costs were examined in terms of annualized costs and annual revenue requirements. The impact on consumers was determined by analyzing the effect of the alternatives on average consumer costs and residential electric bills. The alternatives were also examined in terms of cost per ton of SO_2 removal. Finally, the present value costs of the alternatives were calculated.

The effects of the alternative proposals on energy production and consumption were also analyzed. National coal use was projected and broken down in terms of production and consumption by geographic region. The amount of western coal shipped to the Midwest and East was also estimated. In addition, utility consumption of oil and natural gas was analyzed.

Major Assumptions

Two types of assumptions have an important effect on the results of the analyses. The first group involves the model structure and characteristics. The second group includes the assumptions used to specify future economic conditions.

The utility model selected for this analysis can be characterized as a cost minimizing economic model. In meeting demand, it determines the most economic mix of plant capacity and electric generation for the utility system, based on a consideration of construction and operating costs for new plants and variable costs for existing plants. It also determines the optimum operating level for new and existing plants. This economic-based decision criteria should be kept in mind when analyzing the model results. These criteria imply, for example, that all utilities base decisions on lowest costs and that neutral risk is associated with alternative choices.

Such assumptions may not represent the utility decision making process in all cases. For example, the model assumes that a utility bases supply decisions on the cost of constructing and operating new capacity versus the cost of operating existing capacity. Environmentally, this implies a tradeoff between emissions from new and old sources. The cost minimization assumption implies that in meeting the standard a new power plant will fully scrub high-sulfur coal if this option is cheaper than fully or partially scrubbing low-sulfur coal. Often the model will have to make such a decision, especially in the Midwest where utilities can choose between burning local high-sulfur or imported western low-sulfur coal. The assumption of risk neutrality implies that a utility will always choose the low-cost option. Utilities, however, may perceive full scrubbing as involving more risks and pay a premium to be able to partially scrub the coal. On the other hand, they may perceive risks associated with long-range transportation of coal, and thus opt for full control even though partial control is less costly.

The assumptions used in the analyses to represent economic conditions in a given year have a significant impact on the final results reached. The major assumptions used in the analyses are shown in Table 1 and the significance of these parameters is summarized below.

The growth rate in demand for electric power is very important since this rate determines the amount of new capacity which will be needed and thus directly affects the emission estimates and the projections of pollution control costs. A high electric demand growth rate results in a larger emission reduction associated with the proposed standards and also results in higher costs.

The nuclear capacity assumed to be installed in a given year is also important to the analysis. Because nuclear power is less expensive, the model will predict construction of new nuclear plants rather than new coal plants. Hence, the nuclear capacity assumption affects the amount of new coal capacity which will be required to meet a given electric demand level. In practice, there are a number of constraints which limit the amount of nuclear capacity which can be constructed, but for this study, nuclear capacity was specified approximately

equal to the moderate growth projections of the Department of Energy.

The oil price assumption has a major impact on the amount of predicted new coal capacity, emissions, and oil consumption. Since the model makes generation decisions based on cost, a low oil price relative to the cost of building and operating a new coal plant will result in more oil-fired generation and less coal utilization. This results in less new coal capacity which reduces capital costs but increases oil consumption and fuel costs because oil is more expensive per Btu than coal. This shift in capacity utilization also affects emissions, since an existing oil plant generally has a higher emission rate than a new coal plant even when only partial control is allowed on the new plant.

Coal transportation and mine labor rates both affect the delivered price of coal. The assumed transportation rate is generally more important to the predicted consumption of low-sulfur coal (relative to high-sulfur coal), since that is the coal type which is most often shipped long distances. The assumed mining labor cost is more important to eastern coal costs and production estimates since this coal production is generally much more labor intensive than western coal.

Because of the uncertainty involved in predicting future economic conditions, the Administrator anticipated a large number of comments from the public regarding the modeling assumptions. While the Administrator would have liked to analyze each scenario under a range of assumptions for each critical parameter, the number of modeling inputs made such an approach impractical. To decide on the best assumptions and to limit the number of sensitivity runs, a joint working group was formed. The group was comprised of representatives from the Department of Energy, Council of Economic Advisors, Council on Wage and Price Stability, and others. The group reviewed model results to date, identified the key inputs, specified the assumptions, and identified the critical parameters for which the degree of uncertainty was such that sensitivity analyses should be performed. Three months of study resulted in a number of changes which are reflected in Table 1 and discussed below. These assumptions were used in both the phase 2 and phase 3 analyses.

After more evaluation, the joint working group concluded that the oil prices assumed in the phase 1 analysis were too high. On the other hand, no firm guidance was available as to what oil prices should be used. In view of this, the working group decided that the best course of action was to use two sets of oil prices which reflect the best estimates of those governmental entities concerned with projecting oil prices. The oil price sensitivity analysis was part of the phase 2 analysis which was distributed at the public hearing. Further details are available in the draft report, "Still Further Analysis of Alternative New Source Performance Standards for New Coal-Fired Power Plants (docket number IV-A-5)." The analysis showed that while the variation in oil price affected the magnitude of emissions, costs, and energy impacts, price variation had little effect on the relative impacts of the various NSPS alternatives tested. Based on this conclusion, the higher oil price was selected for modeling purposes since it paralleled more closely the middle range projections by the Department of Energy.

Reassessment of the assumptions made in the phase 1 analysis also revealed that the impact of the coal washing credit had not been considered in the modeling analysis. Other credits allowed by the September proposal, such as sulfur removed by the pulverizers or in bottom ash and flyash, were determined not to be significant when viewed at the national and regional levels. The coal washing credit, on the other hand, was found to have a significant effect on predicted emissions levels and, therefore, was factored into the analysis.

As a result of this reassessment, refinements also were made in the fuel gas desulfurization (FGD) costs assumed. These refinements include changes in sludge disposal costs, energy penalties calculated for reheat, and module sizing. In addition, an error was corrected in the calculation of partial scrubbing costs. These changes have resulted in relatively higher partial scrubbing costs when compared to full scrubbing.

Changes were made in the FGD availability assumption also. The phase 1 analysis assumed 100 percent availability of FGD systems. This assumption, however, was in conflict with EPA's estimates on module availability. In view of this, several alternatives in the phase 2 analysis were modeled at lower system availabilities. The assumed availability was consistent with a 90 percent availability for individual modules when the system is equipped with one spare. The analysis also took into consideration the emergency by-pass provisions of the proposed regulation. The analysis showed that lower reliabilities would result in somewhat higher emissions and costs for both the partial and full control cases. Total coal capacity was slightly lower under full control and slightly higher under partial control. While it was postulated that the lower reliability assumption would produce greater adverse impacts on full control than on partial control options, the relative differences in impacts were found to be insignificant. Hence, the working group discarded the reliability issue as a major consideration in the analyzing of national impacts of full and partial control options. The Administrator still believes that the newer approach better reflects the performance of well designed, operated, and maintained FGD systems. However, in order to expedite the analyses, all subsequent alternatives were analyzed with an assumed system reliability of 100 percent.

Another adjustment to the analysis was the incorporation of dry SO_2 scrubbing systems. Dry scrubbers were assumed to be available for both new and retrofit applications. The costs of these systems were estimated by EPA's Office of Research and Development based on pilot plant studies and contract prices for systems currently under construction. Based on economic analysis, the use of dry scrubbers was assumed for low-sulfur coal (less than 1290 ng/J or 3 lb SO_2/million Btu) applications in which the control requirement was 70 percent or less. For higher sulfur content coals, wet scrubbers were assumed to be more economical. Hence, the scenarios characterized as using "dry" costs contain a mix of wet and dry technology whereas the "wet" scenarios assume wet scrubbing technology only.

Additional refinements included a change in the capital charge rate for pollution control equipment to conform to the Federal tax laws on depreciation, and the addition of 100 billion tons of coal reserves not previously accounted for in the model.

Finally, a number of less significant adjustments were made. These included adjustments in nuclear capacity to reflect a cancellation of a plant, consideration of oil consumption in transporting coal, and the adjustment of costs to 1978 dollars rather than 1975 dollars. It should be understood that all reported costs include the costs of complying with the proposed particulate matter standard and NO_x standards, as well as the sulfur dioxide alternatives. The model does not incorporate the Agency's PSD regulations nor

forthcoming requirements to protect visibility.

Public Comments

Following the September proposal, a number of comments were received on the impact analysis. A great number focused on the model inputs, which were reviewed in detail by the joint working group. Members of the joint working group represented a spectrum of expertise (energy, jobs, environment, inflation, commerce). The following paragraphs discuss only those comments addressed to parts of the analysis which were not discussed in the preceding section.

One commenter suggested that the costs of complying with State Implementation Plan (SIP) regulations and prevention of significant deterioration requirements should not be charged to the standards. These costs are not charged to the standards in the analyses. Control requirements under PSD are based on site specific, case-by-case decisions for which the standards serves as a minimum level of control. Since these judgments cannot be forecasted accurately, no additional control was assumed by the model beyond the requirements of these standards. In addition, the cost of meeting the various SIP regulations was included as a base cost in all the scenarios modeled. Thus, any forecasted cost differences among alternative standards reflect differences in utility expenditures attributable to changes in the standards only.

Another commenter believed that the time horizon for the analysis (1990/1995) was too short since most plants on line at that time will not be subject to the revised standard. Beyond 1995, our data show that many of the power plants on line today will be approaching retirement age. As utilization of older capacity declines, demand will be picked up by newer, better controlled plants. As this replacement occurs, national SO_2 emissions will begin to decline. Based on this projection, the Administrator believes that the 1990–1995 time frame will represent the peak years for SO_2 emissions and is, therefore, the relevant time frame for this analysis.

Use of a higher general inflation rate was suggested by one commenter. A distinction must be made between general inflation rates and real cost escalation. Recognizing the uncertainty of future inflation rates, the EPA staff conducted the economic analysis in a manner that minimized reliance on this assumption. All construction, operating, and fuel costs were expressed as constant year dollars and therefore the analysis is not affected by the inflation rate. Only real cost escalation was included in the economic analysis. The inflation rates will have an impact on the present value discount rate chosen since this factor equals the inflation rate plus the real discount rate. However, this impact is constant across all scenarios and will have little impact on the conclusions of the analysis.

Another commenter opposed the presentation of economic impacts in terms of monthly residential electric bills, since this treatment neglects the impact of higher energy costs to industry. The Administrator agrees with this comment and has included indirect consumer impacts in the analysis. Based on results of previous analysis of the electric utility industry, about half of the total costs due to pollution control are felt as direct increases in residential electric bills. The increased costs also flow into the commercial and industrial sectors where they appear as increased costs of consumer goods. Since the Administrator is unaware of any evidence of a multiplier effect on these costs, straight cost pass through was assumed. Based on this analysis, the indirect consumer impacts (Table 5) were concluded to be equal to the monthly residential bills ("Economic and Financial Impacts of Federal Air and Water Pollution Controls on the Electric Utility Industry," EPA–230/3–76/013, May 1976).

One utility company commented that the model did not adequately simulate utility operation since it did not carry out hour-by-hour dispatch of generating units. The model dispatches by means of load duration curves which were developed for each of 35 demand regions across the United States. Development of these curves took into consideration representative daily load curves, traditional utility reserve margins, seasonal demand variations, and historical generation data. The Administrator believes that this approach is adequate for forecasting long-term impacts since it plans for meeting short-term peak demand requirements.

Summary of Results

The final results of the analyses are presented in Tables 2 through 5 and discussed below. For the three alternative standards presented, emission limits and percent reduction requirements are 30-day rolling averages, and each standard was analyzed with a particulate standard of 13 ng/J (0.03 lb/million Btu) and the proposed NO_x standards. The full control option was specified as a 520 ng/J (1.2 lb/million Btu) emission limit with a 90 percent reduction in potential SO_2 emissions. The other options are the same as full control except when the emissions to the atmosphere are reduced below 260 ng/J (0.6 lb/million Btu) in which case the minimum percent reduction requirement is reduced. The variable control option requires a 70 percent minimum reduction and the partial control option has a 33 percent minimum reduction requirement. The impacts of each option were forecast first assuming the use of wet scrubbers only and then assuming introduction of dry scrubbing technology. In contrast to the September proposal which focused on 1990 impacts, the analytical results presented today are for the year 1995. The Administrator believes that 1995 better represents the differences among alternatives since more new plants subject to the standard will be on line by 1995. Results of the 1990 analyses are available in the public record.

Wet Scrubbing Results

The projected SO_2 emissions from utility boilers are shown by plant type and geographic region in Tables 2 and 3. Table 2 details the 1995 national SO_2 emissions resulting from different plant types and age groups. These standards will reduce 1995 SO_2 emissions by about 3 million tons per year (13 percent) as compared to the current standards. The emissions from new plants directly affected by the standards are reduced by up to 55 percent. The emission reduction from new plants is due in part to lower emission rates and in part to reduced coal consumption predicted by the model. The reduced coal consumption in new plants results from the increased cost of constructing and operating new coal plants due to pollution controls. With these increased costs, the model predicts delays in construction of new plants and changes in the utilization of these plants after start-up. Reduced coal consumption by new plants is accompanied by higher utilization of existing plants and combustion turbines. This shift causes increased emissions from existing coal- and oil-fired plants, which partially offsets the emission reductions achieved by new plants subject to the standard.

Projections of 1995 regional SO_2 emissions are summarized in Table 3. Emissions in the East are reduced by about 10 to 13 percent as compared to predictions under the current standards, whereas Midwestern emissions are reduced only slightly. The smaller reductions in the Midwest are due to a slow growth of new coal-fired capacity.

In general, introductions of coal-fired capacity tends to reduce emissions since new coal plants replace old coal- and oil-fired units which have higher emission rates. The greatest emission reduction occurs in the West and West South Central regions where significant growth is expected and today's emissions are relatively low. For these two regions combined, the full control option reduces emissions by 40 percent from emission levels under the current standards, while the partial and variable options produce reductions of about 30 percent.

Table 4 illustrates the effect of the proposed standards on 1995 coal production, western coal shipped east, and utility oil and gas consumption. National coal production is predicted to triple by 1995 under all the alternative standards. This increased demand raises production in all regions of the country as compared to 1975 levels. Considering these major increases in national production, the small production variations among the alternatives are not large. Compared to production under the current standards, production is down somewhat in the West, Northern Great Plains, and Appalachia, while production is up in the Midwest. These shifts occur because of the reduced economic advantage of low-sulfur coals under the revised standards. While three times higher than 1975 levels, western coal shipped east is lower under all options than under the current standards.

Oil consumption in 1975 was 1.4 million barrels per day. The 3.1 million barrels per day figure for 1975 consumption in Table 4 includes utility natural gas consumption (equivalent of 1.7 million barrels per day) which the analysis assumed would be phased out by 1990. Hence, in 1995, the 1.4 million barrel per day projection under current standards reflects retirement of existing oil capacity and offsetting increases in consumption due to gas-to-oil conversions.

Oil consumption by utilities is predicted to increase under all the options. Compared to the current standards, increased consumption is 200,000 barrels per day under the partial and variable options and 400,000 barrels per day under full control. Oil consumption differences are due to the higher costs of new coal plants under these standards, which causes a shift to more generation from existing oil plants and combustion turbines. This shift in generation mix has important implications for the decision-making process, since the only assumed constraint to utility oil use was the price. For example, if national energy policy imposes other constraints which phase out or stabilize oil use for electric power generation, then the differences in both oil consumption and oil plant emissions (Table 2) across the various standards will be mitigated. Constraining oil consumption, however, will spread cost differences among standards.

The economic effects in 1995 are shown in Table 5. Utility capital expenditures increase under all options as compared to the $770 billion estimated to be required through 1995 in the absence of a change in the standard. The capital estimates in Table 5 are increments over the expenditures under the current standard and include both plant capital (for new capacity) and pollution control expenditures. As shown in Table 2, the model estimates total industry coal capacity to be about 17 GW (3 percent) greater under the non-uniform control options. The cost of this extra capacity makes the total utility capital expenditures higher under the partial and variable options, than under the full control option, even though pollution control capital is lower.

Annualized cost includes levelized capital charges, fuel costs, and operation and maintenance costs associated with utility equipment. All of the options cause an increase in annualized cost over the current standards. This increase ranges from a low of $3.2 billion for partial control to $4.1 billion for full control, compared to the total utility annualized costs of about $175 billion.

The average monthly bill is determined by estimating utility revenue requirements which are a function of capital expenditures, fuel costs, and operation and maintenance costs. The average bill is predicted to increase only slightly under any of the options, up to a maximum 3-percent increase shown for full control. Over half of the large total increase in the average monthly bill over 1975 levels ($25.50 per month) is due to a significant increase in the amount of electricity used by each customer. Pollution control expenditures, including those to meet the current standards, account for about 15 percent of the increase in the cost per kilowatt-hour while the remainder of the cost increase is due to capital intensive capacity expansion and real escalations in construction and fuel cost.

Indirect consumer impacts range from $1.10 to $1.60 per month depending on the alternative selected. Indirect consumer impacts reflect increases in consumer prices due to the increased energy costs in the commercial and industrial sectors.

The incremental costs per ton of SO_2 removal are also shown in Table 5. The figures are determined by dividing the change in annualized cost by the change in annual emissions, as compared to the current standards. These ratios are a measure of the cost effectiveness of the options, where lower ratios represent a more efficient resource allocation. All the options result in higher cost per ton than the current standards with the full control option being the most expensive.

Another measure of cost effectiveness is the average dollar-per-ton cost at the plant level. This figure compares total pollution control cost with total SO_2 emission reduction for a model plant. This average removal cost varies depending on the level of control and the coal sulfur content. The range for full control is from $325 per ton on high-sulfur coal to $1,700 per ton on low-sulfur coal. On low-sulfur coals, the partial control cost is $2,000 per ton, and the variable cost is $1,700 per ton.

The economic analyses also estimated the net present value cost of each option. Present value facilitates comparison of the options by reducing the streams of capital, fuel, and operation and maintenance expenses to one number. A present value estimate allows expenditures occurring at different times to be evaluated on a similar basis by discounting the expenditures back to a fixed year. The costs chosen for the present value analysis were the incremental utility revenue requirements relative to the current NSPS. These revenue requirements most closely represent the costs faced by consumers. Table 5 shows that the present value increment for 1995 capacity is $41 billion for full control, $37 billion for variable control, and $32 billion for partial control.

Dry Scrubbing Results

Tables 2 through 5 also show the impacts of the options under the assumption that dry SO_2 scrubbing systems penetrate the pollution control market. These analyses assume that utilities will install dry scrubbing systems for all applications where they are technologically feasible and less costly than wet systems. (See earlier discussion of assumptions.)

The projected SO_2 emissions from utility boilers are shown by plan type and geographic region in Tables 2 and 3. National emission projections are similar to the wet scrubbing results. Under the dry control assumption, however, the variable control option is predicted to have the lowest national

emissions primarily due to lower oil plant emissions relative to the full control option. Partial control produces more emissions than variable control because of higher emissions from new plants. Compared to the current standards, regional emission impacts are also similar to the wet scrubbing projections. Full control results in the lowest emissions in the West, while variable control results in the lowest emissions in the East. Emissions in the Midwest and West South Central are relatively unaffected by the options.

Inspection of Tables 2 and 3 shows that with the dry control assumption the current standard, full control, and partial control cases produce slightly higher emissions than the corresponding wet control cases. This is due to several factors, the most important of which is a shift in the generation mix. This shift occurs because dry scrubbers have lower capital costs and higher variable costs than wet scrubbers and, therefor, the two systems have different effects on the plant utilization rates. The higher variable costs are due primarily to transportation charges on intermediate to low sulfur coal which must be used with dry scrubbers. The increased variable cost of dry controls alters the dispatch order of existing plants so that older, uncontrolled plants operate at relatively higher capacity factors than would occur under the wet scrubbing assumption, hence increasing total emissions. Another factor affecting emissions is utility coal selection which may be altered by differences in pollution control costs.

Table 4 shows the effect to the proposed standards on fuels in 1995. National coal production remains essentially the same whether dry or wet controls are assumed. However, the use of dry controls causes a slight reallocation in regional coal production, except under a full control option where dry controls cannot be applied to new plants. Under the variable and partial options Appalachian production increases somewhat due to greater demand for intermediate sulfur coals while Midwestern coal production declines slightly. The non-uniform options also result in a small shifting in the western regions with Northern Great Plains production declining and production in the rest of West increasing. The amount of western coal shipped east under the current standard is reduced from 122 million to 99 million tons (20% decrease) due to the increased use of eastern intermediate sulfur coals for dry scrubbing applications. Western coal shipped east is reduced further by the revised standards, to a low of 55 million tons under full control. Oil impacts under the dry control assumption are identical to the wet control cases, with full control resulting in increased consumption of 200 thousand barrels per day relative to the partial and variable options.

The 1995 economic effects of these standards are presented in Table 5. In general, the dry control assumption results in lower costs. However, when comparing the dry control costs to the wet control figures it must be kept in mind that the cost base for comparison, the current standards, is different under the dry control and wet control assumptions. Thus, while the uncremental costs of full control are higher under the dry scrubber assumption the total costs of meeting the standard is lower than if wet controls were used.

The economic impact figures show that when dry controls are assumed the cost savings associated with the variable and partial options is significantly increased over the wet control cases. Relative to full control the partial control option nets a savings of $1.4 billion in annualized costs which equals a $14 billion net present value savings. Variable control results in a $1.1 billion annualized cost savings which is a savings of $12 billion in net present value. These changes in utility costs affect the average residential bill only slightly, with partial control resulting in a savings of $.50 per month and variable control savings of $.40 per month on the average bill, relative to full control.

Conclusions

One finding that has been clearly demonstrated by the two years of analysis is that lower emission standards on new plants do not necessarily result in lower national SO_2 emissions when total emissions from the entire utility system are considered. There are two reasons for this finding. First, the lowest emissions tend to result from strategies that encourage the construction of new coal capacity. This capacity, almost regardless of the alternative analyzed, will be less polluting than the existing coal- or oil-fired capacity that it replaces. Second, the higher cost of operating the new capacity (due to higher pollution costs) may cause the newer, cleaner plants to be utilized less than they would be under a less stringent alternative. These situations are demonstrated by the analyses presented here.

The variable control option produces emissions that are equal to or lower than the other options under both the wet and dry scrubbing assumptions. Compared to full control, variable control is predicted to result in 12 GW to 17 GW more coal capacity. This additional capacity replaces dirtier existing plants and compensates for the slight increase in emissions from new plants subject to the standards, hence causing emissions to be less than or equal to full control emissions depending on scrubbing cost assumption (i.e., wet or dry). Partial control and variable control produce about the same coal capacity, but the additional 300 thousand ton emission reduction from new plants causes lower total emissions under the variable option. Regionally, all the options produce about the same emissions in the Midwest and West South Central regions. Full control produces 200 thousands tons less emissions in the West than the variable option and 300 thousand tons less than partial control. But the variable and partial options produce between 200 and 300 thousand tons less emissions in the East.

The variable and partial control options have a clear advantage over full control with respect to costs under both the wet and dry scrubbing assumptions. Under the dry assumption, which the Administrator believes represents the best prediction of utility behavior, variable control saves about $1.1 billion per year relative to full control and partial control saves an additional $0.3 billion.

All the options have similar impacts on coal production especially when considering the large increase predicted over 1975 production levels. With respect to oil consumption, however, the full control option causes a 200,000 barrel per day increase as compared to both the partial and variable options.

Based on these analyses, the Administrator has concluded that a non-uniform control strategy is best considering the environmental, energy, and economic impacts at both national and regional levels. Compared to other options analyzed, the variable control standard presented above achieves the lowest emissions in an efficient manner and will not disrupt local or regional coal markets. Moreover, this option avoids the 200 thousand barrel per day oil penalty which has been predicted under a number of control options. For these reasons, the Administrator believes that the variable control option provides the best balance of national environmental, energy, and economic objectives.

Table 1.—*Key Modeling Assumptions*

Assumption	
Growth rates	1975–1985: 4.8%/yr. 1985–1995: 4.0%.
Nuclear capacity	1985: 97 GW. 1990: 165. 1995: 226.
Oil prices ($ 1975)	1985: $12.90/bbl. 1990: $16.40. 1995: $21.00.
Coal transportation	1% per year real increase.
Coal mining labor costs	U M W settlement and 1% real increase thereafter.
Capital charge rate	12.5% for pollution control expenditures.
Cost reporting basis	1978 dollars.
FGD costs	No change from phase 2 analysis except for the addition of dry scrubbing systems for certain applications.
Coal cleaning credit	5%–35% SO_2 reduction assumed for high sulfur bituminous coals only.
Bottom ash and fly ash content	No credit assumed.

Table 2.—*National 1995 SO_2 Emissions From Utility Boilers*[a]

[Million tons]

Plant category	1975 actual	Level of control[b]: Current standards		Full control		Partial control 33% minimum		Variable control 70% minimum	
		Wet[d]	*Dry*[e]	*Wet*	*Dry*	*Wet*	*Dry*	*Wet*	*Dry*
SIP/NSPS Plants[c]		15.5	15.8	16.0	16.2	15.9	16.2	16.0	16.1
New Plants[f]		7.1	7.0	3.1	3.1	3.6	3.4	3.3	3.1
Oil Plants		1.0	1.0	1.4	1.4	1.3	1.2	1.3	1.2
Total National Emissions	18.6	23.7	23.8	20.6	20.7	20.8	20.9	20.6	20.5
Total Coal Capacity (GW)	205	552	554	521	520	534	537	533	537
Sludge generated (million tons dry)		23	27	55	56	43	39	50	41

[a] Results of joint EPA/DOE analyses completed in May 1979 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.
[b] With 520 ng/J maximum emission limit.
[c] Plants subject to existing State regulations or the current NSPS of 1.2 lb SO_2/million BTU.
[d] Based on wet SO_2 scrubbing costs.
[e] Based on dry SO_2 scrubbing costs where applicable.
[f] Plants subject to the revised standards.

Table 3.—*Regional 1995 SO_2 Emissions From Utility Boilers*[a]

[Million tons]

	1975 actual	Level of control[b]: Current standards		Full control		Partial control 33% minimum		Variable control 70% minimum	
		Wet[c]	*Dry*[d]	*Wet*	*Dry*	*Wet*	*Dry*	*Wet*	*Dry*
Total National Emissions	18.6	23.7	23.8	20.6	20.7	20.8	20.9	20.6	20.5
Regional Emissions:									
East[e]		11.2	11.2	10.1	10.1	9.8	9.8	9.8	9.7
Midwest[f]		8.1	8.3	7.9	7.9	7.9	8.0	7.9	8.0
West South Central[g]		2.6	2.6	1.7	1.7	1.8	1.8	1.8	1.7
West[h]		1.7	1.7	0.9	0.9	1.2	1.2	1.1	1.1
Total Coal Capacity (GW)	205	552	554	521	520	534	537	533	537

[a] Results of joint EPA/DOE analyses completed in May 1979 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.
[b] With 520 ng/J maximum emission limit.
[c] Based on wet SO_2 scrubbing costs.
[d] Based on dry SO_2 scrubbing costs where applicable.
[e] New England, Middle Atlantic, South Atlantic, and East South Central Census Regions.
[f] East North Central and West North Central Census Regions.
[g] West South Central Census Region.
[h] Mountain and Pacific Census Regions.

Performance Testing

Particulate Matter

The final regulations require that Method 5 or 17 under 40 CFR Part 60, Appendix A, be used to determine compliance with the particulate matter emission limit. Particulate matter may be collected with Method 5 at an outstack filter temperature up to 160 C (320 F); Method 17 may be used when stack temperatures are less than 160 C (320 F). Compliance with the opacity standard in the final regulation is determined by means of Method 9, under 40 CFR Part 60, Appendix A. A transmissometer that meets Performance Specification 1 under 40 CFR Part 60, Appendix B is required.

Several comments were received which questioned the accuracy of Methods 5 and 17 when used to measure particulate matter at the level of the standard. The accuracy of Methods 5 and 17 is dependent on the amount of sample collected and not the concentration in the gas stream. To maintain an accuracy comparable to the accuracy obtained when testing for mass emission rates higher than the standard, it is necessary to sample for longer times. For this reason, the regulation requires a minimum sampling time of 120 minutes and a minimum sampling volume of 1.7 dscm (60 dscf).

Three comments raised the issue of potential interference of acid mist with the measurement of particulate matter. The Administrator recognized this issue prior to proposal of the regulations. In the preamble to the proposed regulations, the Administrator indicated that investigations would continue to determine the extent of the problem. A series of tests at an FGD-equipped facility burning 3-percent-sulfur coal indicate that the amount of sample collected using Method 5 precedures is temperature sensitive over the range of filter temperatures used (250° F to 380° F), with reduced weights at higher temperatures. Presumably, the decreased weight at higher filter temperatures reflect vaporization of acid mist. Recently received particulate emission data using Method 5 at 32° F for a second coal-fired power plant equipped with an electrostatic precipitator and an FGD system apparently conflicts with the data generated by EPA. For this plant, particulate matter was measured at 0.02 lbs/million Btu. It is not known what portion of this particulate matter, if any was attributable to sulfuric acid mist.

The intent of the particulate matter standard is to insure the installation, operation, and maintenance of a good

Table 4—*Impacts on Fuels in 1995*[a]

		Level of control[b]							
	1975 actual	Current standards		Full control		Partial control 33% minimum		Variable control 70% minimum	
		Wet[c]	*Dry*[d]	*Wet*	*Dry*	*Wet*	*Dry*	*Wet*	*Dry*
U S Coal Production (million tons)									
Appalachia	396	489	524	463	465	475	486	470	484
Midwest	151	404	391	487	488	456	452	465	450
Northern Great Plains	54	655	630	633	628	622	576	632	602
West	46	230	222	182	180	212	228	203	217
Total	647	1,778	1,767	1,765	1,761	1,765	1,742	1,770	1,752
Western Coal Shipped East (million tons)	21	122	99	59	55	68	59	71	70
Oil Consumpton by Power Plants (million bbl/day).									
Power Plants		1 2	1.2	1 6	1 6	1 4	1.4	1.4	1.4
Coal Transportation		0.2	0.2	0.2	0.2	0 2	0.2	0.2	0.2
Total	3 1	1.4	1.4	1.8	1.8	1.6	1 6	1 6	1.6

[a] Results of EPA analyses completed in May 1979 based on oil prices of $12 90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively

[b] With 520ng/J maximum emission limit.

[c] Based on wet SO_2 scrubbing costs

[d] Based on dry SO_2 scrubbing where applicable.

Table 5.—*1995 Economic Impacts*[a]

[1978 dollars]

	Level of control[b]							
	Current standards		Full control		Partial control 33% minimum		Variable control 70% minimum	
	Wet[c]	*Dry*[d]	*Wet*	*Dry*	*Wet*	*Dry*	*Wet*	*Dry*
Average Monthly Residential Bills ($/month)	$53.00	$52 85	$54 50	$54 45	$54.15	$53 95	$54 30	$54.05
Indirect Consumer Impacts ($/month)			1.50	1.60	1 15	1 10	1.30	1.20
Incremental Utility Capital Expenditures, Cumulative 1976–1995 ($ billions)			4	5	6	−3	10	−1
Incremental Annualized Cost ($ billions)			4.1	4.4	3.2	3.0	3 6	3.3
Present Value of Incremental Utility Revenue Requirements ($ billions)			41	45	32	31	37	33
Incremental Cost of SO^2 Reduction ($/ton)			1,322	1,428	1,094	1,012	1,163	1,036

[a] Results of EPA analyses completed in May 1979 based on oil prices of $12 90, $16.40, and $21 00/bbl in the years 1985, 1990, and 1995, respectively.

[b] With 520 ng/J maximum emission limit.

[c] Based on wet SO_2 scrubbing costs.

[d] Based on dry SO_2 scrubbing costs where applicable.

emission control system. Since technology is not available for the control of sulfuric acid mist, which is condensed in the FGD system, the Administrator does not believe the particulate matter sample should include condensed acid mist. The final regulation, therefore, allows particulate matter testing for compliance between the outlet of the particulate matter control device and the inlet of a wet FGD system. EPA will continue to investigate revised procedures to minimize the measurement of acid mist by Methods 5 or 17 when used to measure particulate matter after the FGD system. Since technology is available to control particulate sulfate carryover from an FGD system, and the Administrator believes good mist eliminators should be included with all FGD systems, the regulations will be amended to require particulate matter measurement after the FGD system when revised procedures for Methods 5 or 17 are available.

SO_2 and NO_x

The final regulation requires that compliance with the sulfur dioxide and nitrogen oxides standards be determined by using continuous monitoring systems (CMS) meeting Performance Specifications 2 and 3, under 40 CFR Part 60, Appendix B. Data from the CMS are used to calculate a 30-day rolling average emission rate and percentage reduction (sulfur dioxide only) for the initial performance test required under 40 CFR 60.8. At the end of each boiler operating day after the initial performance test a new 30-day rolling average emission rate for sulfur dioxide and nitrogen oxides and an average percent reduction for sulfur dioxide are determined. The final regulations specify the minimum amount of data that must be obtained for each 30 successive boiler operating days but requires the calculation of the average emission rate and percentage reduction based on all available data. The minimum data requirements can be satisfied by using the Reference Methods or other approved alternative methods when the CMS, or components of the system, are inoperative.

The final regulation requires operation of the continuous monitors at all times, including periods of startup, shutdown, malfunction (NO_x only), and emergency conditions (SO_2 only), except for those periods when the CMS is inoperative because of malfunctions, calibration or span checks.

The proposed regulations would have required that compliance be based on the emission rate and percent reduction

(sulfur dioxide only) for each 24-hour period of operation. Continual determination of compliance with the proposed standard would have necessitated that each source owner or operator install redundant CMS or conduct manual testing in the event of CMS malfunction.

Comments on the proposed testing requirements for sulfur dioxide and nitrogen oxides indicated that CMS could not operate without malfunctions; therefore, every facility would require redundant CMS. One commenter calculated that seven CMS would be needed to provide the required data. Comments also questioned the practicality and feasibility of obtaining around-the-clock emissions data by means of manual testing in the event of CMS malfunction. The commenter stated that the need for immediate backup testing using manual methods would require a stand-by test team at all times and that extreme weather conditions or other circumstances could often make it impossible for the test team to obtain the required data. The Administrator agrees with these comments and has redefined the data requirements to reflect the performance that can be achieved with one well-maintained CMS. The final requirements are designed to eliminate the need for redundant CMS and minimize the possibility that manual testing will be necessary, while assuring acquisition of sufficient data to document compliance.

Compliance with the emission limitations for sulfur dioxide and nitrogen oxides and the percentage reduction for sulfur dioxide is determined from all available hourly averages, except for periods of startup, shutdown, malfunction or emergency conditions for each 30 successive boiler operating days. Minimum data requirements have been established for hourly averages, for 24-hour periods, and for the 30 successive boiler operating days. These minimum requirements eliminate the need for redundant CMS and minimize the need for testing using manual sampling techniques. The minimum requirements apply separately to inlet and outlet monitoring systems.

The regulation allows calculation of hourly averages for the CMS using two or more of the required four data points. This provision was added to accommodate those monitors for which span and calibration checks and minor repairs might require more than 15 minutes.

For any 24-hour period, emissions data must be obtained for a minimum of 75 percent of the hours during which the affected facility is operated (including startup, shutdown, malfunctions or emergency conditions). This provision was added to allow additional time for CMS calibrations and to correct minor CMS problems, such as a lamp failure, a plugged probe, or a soiled lens. Statistical analyses of data obtained by EPA show that there is no significant difference (at the 95 percent confidence interval) between 24-hour means based on 75 percent of the data and those based on the full data set.

To provide time to correct major CMS malfunctions and minimize the possibility that supplemental testing will be needed, a provision has been added which allows the source owner or operator to demonstrate compliance if the minimum data for each 24-hour period has been obtained for 22 of the 30 successive boiler operating days. This provision is based on EPA studies that have shown that a single pair of CMS pollutant and diluent monitors can be made available in excess of 75 percent of the time and several comments showing CMS availability in excess of 90 percent of the time.

In the event a CMS malfunction would prevent the source owner or operator from meeting the minimum data requirements, the regulation requires that the reference methods or other procedures approved by the Administrator be used to supplement the data. The Administrator believes, however, that a single properly designed, maintained, and operated CMS with trained personnel and an appropriate inventory of spare parts can achieve the monitoring requirements with currently available CMS equipment. In the event that an owner or operator fails to meet the minimum data requirements, a procedure is provided which may be used by the Administrator to determine compliance with the SO_2 and NO_x standards. The procedure is provided to reduce potential problems that might arise if an owner or operation is unable to meet the minimum data requirements or attempts to manipulate the acquisition of data so as to avoid the demonstration of noncompliance. The Administrator believes that an owner or operator should not be able to avoid a finding of noncompliance with the emission standards solely by noncompliance with the minimum data requirements. Penalties related only to failure to meet the minimum data requirements may be less than those for failure to meet the emission standards and may not provide as great an incentive to maintain compliance with the regulations.

The procedure involves the calculation of standard deviations for the available inlet SO_2 monitoring data and the available outlet SO_2 and NO_x monitoring data and assumes the data are normally distributed. The standard deviation of the inlet monitoring data for SO_2 is used to calculate the upper confidence limit of the inlet emission rate at the 95 percent confidence interval. The upper confidence limit of the inlet emission rate is used to determine the potential combustion concentration and the allowable emission rate. The standard deviation of the outlet monitoring data for SO_2 and NO_x are used to calculate the lower confidence limit of the outlet emission rates at the 95 percent confidence interval. The lower confidence limit of the outlet emission rate is compared with the allowable emission rate to determine compliance. If the lower confidence limit of the outlet emission rate is greater than the allowable emission rate for the reporting period, the Administrator will conclude that noncompliance has occurred.

The regulations require the source owner or operator who fails to meet the minimum data requirements to perform the calculations required by the added procedure, and to report the results of the calculations in the quarterly report. The Administrator may use this information for determining the compliance status of the affected facility.

It is emphasized that while the regulations permit a determination of the compliance status of a facility in the absence of data reflecting some periods of operation, an owner and operator is required by 40 CFR 60.11(d) to continue to operate the facility at all times so as to minimize emissions consistent with good engineering practice. Also, the added procedure which allows for a determination of compliance when less than the minimum monitoring data have been obtained does not exempt the source owner or operator from the minimum data requirements. Exemption from the minimum data requirements could allow the source owner to circumvent the standard, since the added procedure assumes random variations in emission rates.

One commenter suggested that operating data be used in place of CMS data to demonstrate compliance. The Administrator does not believe, however, that the demonstration of compliance can be based on operating data alone. Consideration was given to the reporting of operating parameters during those periods when emissions data have not been obtained. This

alternative was rejected because it would mean that the source owner or operator would need to record the operating parameters at all times, and would impose an administrative burden on source owners or operators in compliance with the emission monitoring requirements. The regulation requires the owner or operator to certify that the emission control systems have been kept in operation during periods when emissions data have not been obtained.

Several commenters indicated that CMS were not sufficiently accurate to allow for a determination of compliance. One commenter provided calculations showing that the CMS could report an FGD efficiency ranging from 77.5 to 90 percent, with the scrubber operating at an efficiency of 85 percent. The analysis submitted by the commenter is theoretically possible for any single data point generated by the CMS. For the 30-day averaging periods, however, random variations in individual data points are not significant. The criterion of importance in showing compliance for this longer averaging time is the difference between the mean values measured by the CMS and the reference methods. EPA is developing quality assurance procedures, which will require a periodic demonstration that the mean emission rates measured by the CMS demonstrates a consistent and reproducible relationship with the mean emission rates measured by the reference methods or acceptable modifications of these methods.

A specific comment received on the monitoring requirements questioned the need to respan the CMS for sulfur dioxide when the sulfur content of the fuel changed by 0.5 percent. The intent of this requirement was to assure that a change in fuel sulfur content would not result in emissions exceeding the range of the CMS. This requirement has been deleted on the premise that the source owner or operator will initiate his own procedures to protect himself against loss of data.

Several comments were also received concerning detailed technical items contained in Performance Specifications 2 and 3. One comment, for example, suggested that a single "relative accuracy" specification be used for the entire CMS, as opposed to separate values for the pollutant and diluent monitors. Another comment questioned the performance specification on instrument response time, while still other comments raised questions on calibration procedures. EPA is in the process of revising Performance Specifications 2 and 3 to respond to these, and other questions. The current performance specifications, however, are adequate for the determination of compliance.

Fuel Pretreatment

The final regulation allows credit for fuel pretreatment to remove sulfur or increase heat content. Fuel pretreatment credits are determined in accordance with Method 19. This means that coal or oil may be treated before firing and the sulfur removed may be credited toward meeting the SO_2 percentage reduction requirement. The final fuel pretreatment provisions are the same as those proposed.

Most all commenters on this issue supported the fuel pretreatment crediting procedures proposed by EPA. Several commenters requested that credit also be given for sulfur removed in the coal bottom ash and fly ash. This is allowed under the final regulation and was also allowed under the proposal in the optional "as-fired" fuel sampling procedures under the SO_2 emission monitoring requirements. By monitoring SO_2 emissions (ng/J, lb/million Btu) with an as-fired fuel sampling system located upstream of coal pulverizers and with an in-stack continuous SO_2 monitoring system downstream of the FGD system, sulfur removal credits are combined for the coal pulverizer, bottom ash, fly ash and FGD system into one removal efficiency. Other alternative sampling procedures may also be submitted to the Administrator for approval.

Several commenters indicated that they did not understand the proposed fuel pretreatment crediting procedure for refined fuel oil. The Administrator intended to allow fuel pretreatment credits for all fuel oil desulfurization processes used in preparation of utility boiler fuels. Thus, the input and output from oil desulfurization processes (e.g., hydrotreatment units) that are used to pretreat utility boiler fuels used in determining pretreatment credits. If desulfurized oil is blended with undesulfurized oil, fuel pretreatment credits are prorated based on heat input of oils blended. The Administrator believes that the oil input to the desulfurizer should be considered the input for credit determination and not the well head crude oil or input oil to the refinery. Refining of crude oil results in the separation of the base stock into various density fractions which range from lighter products such as naphtha and distillate oils. Most of the sulfur from the crude oil is bound to the heavier residual oils which may have a sulfur content of twice the input crude oil. The residual oils can be upgraded to a lower sulfur utility steam generator fuel through the use of desulfurization technology (such as hydrodesulfurization). The Administrator believes that it is appropriate to give full fuel pretreatment credit for hydrotreatment units and not to penalize hydrodesulfurization units which are used to process high-sulfur residual oils. Thus, the input to the hydrodesulfurization unit is used to determine oil pretreatment credits and not the lower sulfur refinery input crude. This procedure will allow full credit for residual oil hydrodesulfurization units.

In relation to fuel pretreatment credits for coal, commenters requested that sampling be allowed prior to the initial coal breaker. Under the final standards, coal sampling may be conducted at any location (either before or after the initial coal breaker). It is desirable to sample coal after the initial breaker because the smaller coal volume and coal size will reduce sampling requirements under Method 19. If sampling were conducted before the initial breaker, rock removed by the coal breaker would not result in any additional sulfur removal credit. Coal samples are analyzed to determine potential SO_2 emissions in ng/J (lb/million Btu) and any removal of rock or other similar reject material will not change the potential SO_2 emission rate (ng/J; lb/million Btu).

An owner or operator of an affected facility who elects to use fuel pretreatment credits is responsible for insuring that the EPA Method 19 procedures are followed in determining SO_2 removal credit for pretreatment equipment.

Miscellaneous

Establishment of standards of performance for electric utility steam generating units was preceded by the Administrator's determination that these sources contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare (36 FR 5931), and by proposal of regulations on September 19, 1978 (43 FR 42154). In addition, a preproposal public hearing (May 25–26, 1977) and a postproposal public hearing (December 12–13, 1978) was held after notification was given in the Federal Register. Under section 117 of the Act, publication of these regulations was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

Standards of performance for new fossil-fuel-fired stationary sources established under section 111 of the Clean Air Act reflect:

Application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. [section 111(a)(1)]

Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act requires (or has potential for requiring) the imposition of a more stringent emission standard in several situations.

For example, applicable costs do not play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources located in nonattainment areas, i.e., those areas where statutorily-mandated health and welfare standards are being violated. In this respect, section 173 of the Act requires that a new or modified source constructed in an area that exceeds the National Ambient Air Quality Standard (NAAQS) must reduce emissions to the level that reflects the "lowest achievable emission rate" (LAER), as defined in section 171(3), for such source category. The statute defines LAER as that rate of emission which reflects:

(A) The most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or

(B) The most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent.

In no event can the emission rate exceed any applicable new source performance standard [section 171(3)].

A similar situation may arise under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require that certain sources [referred to in section 169(1)] employ "best available control technology" [as defined in section 169(3)] for all pollutants regulated under the Act. Best available control technology (BACT) must be determined on a case-by-case basis, taking energy, environmental and economic impacts, and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the Act.

In all events, State implementation plans (SIP's) approved or promulgated under section 110 of the Act must provide for the attainment and maintenance of National Ambient Air Quality Standards designed to protect public health and welfare. For this purpose, SIP's must in some cases require greater emission reductions than those required by standards of performance for new sources.

Finally, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

Under EPA's sunset policy for reporting requirements in regulations, the reporting requirements in this regulation will automatically expire five years from the date of promulgation unless the Administrator takes affirmative action to extend them. Within the five year period, the Administrator will review these requirements.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for revisions determined by the Administrator to be substantial. The Administrator has determined that these revisions are substantial and has prepared an economic impact assessment and included the required information in the background information documents.

Dated: June 1, 1979.

Douglas M. Costle,

Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

In 40 CFR Part 60, § 60.8 of Subpart A is revised, the heading and § 60.40 of Subpart D are revised, a new Subpart Da is added, and a new reference method is added to Appendix A as follows:

1. Section 60.8(d) and § 60.8(f) are revised as follows:

§ 60.8 Performance tests.

* * * * *

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present.

* * * * *

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

2. The heading for Subpart D is revised to read as follows:

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971

3. Section 60.40 is amended by adding paragraph (d) as follows:

§ 60.40 Applicability and designation of affected facility.

* * * * *

(d) Any facility covered under Subpart Da is not covered under This Subpart.

(Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)).)

4. A new Subpart Da is added as follows:

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18,1978

Sec.

60.40a Applicability and designation of affected facility.
60.41a Definitions.
60.42a Standard for particulate matter.
60.43a Standard for sulfur dioxide.
60.44a Standard for nitrogen oxides.
60.45a Commercial demonstration permit.
60.46a Compliance provisions.
60.47a Emission monitoring.
60.48a Compliance determination procedures and methods.
60.49a Reporting requirements.

Authority: Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978

§ 60.40a Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction or modification is commenced after September 18, 1978.

(b) This subpart applies to electric utility combined cycle gas turbines that are capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to Subpart GG.)

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

§ 60.41a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

"Steam generating unit" means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

"Electric utility steam generating unit" means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

"Subbituminous coal" means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388–66.

"Lignite" means coal that is classified as lignite A or B according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388–66.

"Coal refuse" means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

"Potential combustion concentration" means the theoretical emissions (ng/J, lb/million Btu heat input) that would result from combustion of a fuel in an uncleaned state 9without emission control systems) and:

(a) For particulate matter is:

(1) 3,000 ng/J (7.0 lb/million Btu) heat input for solid fuel; and

(2) 75 ng/J (0.17 lb/million Btu) heat input for liquid fuels.

(b) For sulfur dioxide is determined under § 60.48a(b).

(c) For nitrogen oxides is:

(1) 290 ng/J (0.67 lb/million Btu) heat input for gaseous fuels;

(2) 310 ng/J (0.72 lb/million Btu) heat input for liquid fuels; and

(3) 990 ng/J (2.30 lb/million Btu) heat input for solid fuels.

"Combined cycle gas turbine" means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

"Interconnected" means that two or more electric generating units are electrically tied together by a network of power transmission lines, and other power transmission equipment.

"Electric utility company" means the largest interconnected organization, business, or governmental entity that generates electric power for sale (e.g., a holding company with operating subsidiary companies).

"Principal company" means the electric utility company or companies which own the affected facility.

"Neighboring company" means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

"Net system capacity" means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

"System load" means the entire electric demand of an electric utility company's service area interconnected with the affected facility that has the malfunctioning flue gas desulfurization system plus firm contractual sales to other electric utility companies. Sales to other electric utility companies (e.g., emergency power) not on a firm contractual basis may also be included in the system load when no available system capacity exists in the electric utility company to which the power is supplied for sale.

"System emergency reserves" means an amount of electric generating capacity equivalent to the rated capacity of the single largest electric generating unit in the electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) which is interconnected with the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

"Available system capacity" means the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity.

"Spinning reserve" means the sum of the unutilized net generating capability of all units of the electric utility company that are synchronized to the power distribution system and that are capable of immediately accepting

additional load. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

"Available purchase power" means the lesser of the following:

(a) The sum of available system capacity in all neighboring companies.

(b) The sum of the rated capacities of the power interconnection devices between the principal company and all neighboring companies, minus the sum of the electric power load on these interconnections.

(c) The rated capacity of the power transmission lines between the power interconnection devices and the electric generating units (the unit in the principal company that has the malfunctioning flue gas desulfurization system and the unit(s) in the neighboring company supplying replacement electrical power) less the electric power load on these transmission lines.

"Spare flue gas desulfurization system module" means a separate system of sulfur dioxide emission control equipment capable of treating an amount of flue gas equal to the total amount of flue gas generated by an affected facility when operated at maximum capacity divided by the total number of nonspare flue gas desulfurization modules in the system.

"Emergency condition" means that period of time when:

(a) The electric generation output of an affected facility with a malfunctioning flue gas desulfurization system cannot be reduced or electrical output must be increased because:

(1) All available system capacity in the principal company interconnected with the affected facility is being operated, and

(2) All available purchase power interconnected with the affected facility is being obtained, or

(b) The electric generation demand is being shifted as quickly as possible from an affected facility with a malfunctioning flue gas desulfurization system to one or more electrical generating units held in reserve by the principal company or by a neighboring company, or

(c) An affected facility with a malfunctioning flue gas desulfurization system becomes the only available unit to maintain a part or all of the principal company's system emergency reserves and the unit is operated in spinning reserve at the lowest practical electric generation load consistent with not causing significant physical damage to the unit. If the unit is operated at a higher load to meet load demand, an emergency condition would not exist unless the conditions under (a) of this definition apply.

"Electric utility combined cycle gas turbine" means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Potential electrical output capacity" is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100-MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33-MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

"Anthracite" means coal that is classified as anthracite according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-66.

"Solid-derived fuel" means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, and gasified coal.

"24-hour period" means the period of time between 12:01 a.m. and 12:00 midnight.

"Resource recovery unit" means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

"Noncontinental area" means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

"Boiler operating day" means a 24-hour period during which fossil fuel is combusted in a steam generating unit for the entire 24 hours.

§ 60.42a Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the particulate matter performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

§ 60.43a Standard for sulfur dioxide.

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases which contain sulfur dioxide in excess of:

(1) 520 ng/J (1.20 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/million Btu) heat input.

(b) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section), any gases which contain sulfur dioxide in excess of:

(1) 340 ng/J (0.80 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.

(c) On and after the date on which the initial performance test required to be

conducted under § 60.8 is complete, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC–I) any gases which contain sulfur dioxide in excess of 520 ng/J (1.20 lb/million Btu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/million Btu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite,

(2) Is classified as a resource recovery facility, or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dixoide emissions are limited to 340 ng/J (0.80 lb/million Btu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an SO_2 commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.45a.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

(1) If emissions of sulfur dioxide to the atmosphere are greater than 260 ng/J (0.60 lb/million Btu) heat input

$E_{SO_2} = [340\ x + 520\ y]/100$ and
$P_{SO_2} = 10$ percent

(2) If emissions of sulfur dioxide to the atmosphere are equal to or less than 260 ng/J (0.60 lb/million Btu) heat input:

$E_{SO_2} = [340\ x + 520\ y]/100$ and
$P_{SO_2} = [90\ x + 70\ y]/100$

where:

E_{SO_2} is the prorated sulfur dioxide emission limit (ng/J heat input),

P_{SO_2} is the percentage of potential sulfur dioxide emission allowed (percent reduction required = $100 - P_{SO_2}$),

x is the percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels)

y is the percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels)

§ 60.44a Standard for nitrogen oxides.

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraph (b) of this section, any gases which contain nitrogen oxides in excess of the following emission limits, based on a 30-day rolling average.

(1) NO_x Emission Limits—

Fuel type	Emission limit ng/J (lb/million Btu) heat input	
Gaseous Fuels:		
Coal-derived fuels	210	(0.50)
All other fuels	86	(0.20)
Liquid Fuels		
Coal-derived fuels	210	(0.50)
Shale oil	210	(0.50)
All other fuels	130	(0.30)
Solid Fuels:		
Coal-derived fuels	210	(0.50)
Any fuel containing more than 25%, by weight, coal refuse	Exempt from NO_x standards and NO_x monitoring requirements	
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace	340	(0.80)
Lignite not subject to the 340 ng/J heat input emission limit	260	(0.60)
Subbituminous coal	210	(0.50)
Bituminous coal	260	(0.60)
Anthracite coal	260	(0.60)
All other fuels	260	(0.60)

(2) NO_x reduction requirements—

Fuel type	Percent reduction of potential combustion concentration
Gaseous fuels	25%
Liquid fuels	30%
Solid fuels	65%

(b) The emission limitations under paragraph (a) of this section do not apply to any affected facility which is combusting coal-derived liquid fuel and is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.45a.

(c) When two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$E_{NO_x} = [86\ w + 130\ x + 210\ y + 260\ z]/100$

where:

E_{NO_x} is the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input);

w is the percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x is the percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y is the percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard; and

z is the percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard.

§ 60.45a Commercial demonstration permit.

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC–I) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under § 60.43a(c) but must, as a minimum, reduce SO_2 emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(c) An owner or operator of a fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under § 60.43a(a) but must, as a minimum, reduce SO_2 emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable NO_x emission limitation and percent reduction under § 60.44a(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/million Btu)

heat input on a 30-day rolling average basis.

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Solid solvent refined coal (SRC I)	SO_2	6,000–10,000
Fluidized bed combustion (atmospheric)	SO_2	400–3,000
Fluidized bed combustion (pressurized)	SO_2	400–1,200
Coal liquification	NO_x	750–10,000
Total allowable for all technologies		15,000

§ 60.46a Compliance provisions.

(a) Compliance with the particulate matter emission limitation under § 60.42a(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under § 60.42a(a)(2) and (3).

(b) Compliance with the nitrogen oxides emission limitation under § 60.44a(a) constitutes compliance with the percent reduction requirements under § 60.44a(a)(2).

(c) The particulate matter emission standards under § 60.42a and the nitrogen oxides emission standards under § 60.44a apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide emission standards under § 60.43a apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the procedures under paragraph (d) of this section are implemented.

(d) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:

(1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,

(2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation, and

(3) Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 million Btu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph (a), (b), (d), (e), and (i) under § 60.43a for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,

(ii) The affected facility is operating at the maximum heat input rate,

(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(iv) The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

(e) After the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under § 60.43a and the nitrogen oxides emission limitations under § 60.44a is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

(f) For the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under § 60.43a and the nitrogen oxides emission limitation under § 60.44a is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) Compliance is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_x only), or emergency conditions (SO_2 only). Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under § 60.47a of this subpart, compliance of the affected facility with the emission requirements under §§ 60.43a and 60.44a of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in sections 6.0 and 7.0 of Reference Method 19 (Appendix A).

§ 60.47a Emission monitoring.

(a) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.

(2) For a facility which qualifies under the provisions of § 60.43a(d), sulfur dioxide emissions are only monitored as discharged to the atmosphere.

(3) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 (Appendix A) may be used to determine

potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required under paragraph (b)(1) of this section.

(c) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

(e) The continuous monitoring systems under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(f) When emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using other monitoring systems as approved by the Administrator or the reference methods as described in paragraph (h) of this section to provide emission data for a minimum of 18 hours in at least 22 out of 30 successive boiler operating days.

(g) The 1-hour averages required under paragraph § 60.13(h) are expressed in ng/J (lbs/million Btu) heat input and used to calculate the average emission rates under § 60.46a. The 1-hour averages are calculated using the data points required under § 60.13(b). At least two data points must be used to calculate the 1-hour averages.

(h) Reference methods used to supplement continuous monitoring system data to meet the minimum data requirements in paragraph § 60.47a(f) will be used as specified below or otherwise approved by the Administrator.

(1) Reference Methods 3, 6, and 7, as applicable, are used. The sampling location(s) are the same as those used for the continuous monitoring system.

(2) For Method 6, the minimum sampling time is 20 minutes and the minimum sampling volume is 0.02 dscm (0.71 dscf) for each sample. Samples are taken at approximately 60-minute intervals. Each sample represents a 1-hour average.

(3) For Method 7, samples are taken at approximately 30-minute intervals. The arithmetic average of these two consective samples represent a 1-hour average.

(4) For Method 3, the oxygen or carbon dioxide sample is to be taken for each hour when continuous SO_2 and NO_x data are taken or when Methods 6 and 7 are required. Each sample shall be taken for a minimum of 30 minutes in each hour using the integrated bag method specified in Method 3. Each sample represents a 1-hour average.

(5) For each 1-hour average, the emissions expressed in ng/J (lb/million Btu) heat input are determined and used as needed to achieve the minimum data requirements of paragraph (f) of this section.

(i) The following procedures are used to conduct monitoring system performance evaluations under § 60.13(c) and calibration checks under § 60.13(d).

(1) Reference method 6 or 7, as applicable, is used for conducting performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems.

(2) Sulfur dioxide or nitrogen oxides, as applicable, is used for preparing calibration gas mixtures under performance specification 2 of appendix B to this part.

(3) For affected facilities burning only fossil fuel, the span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows:

Fossil fuel	Span value for nitrogen oxides (ppm)
Gas	500
Liquid	500
Solid	1,000
Combination	500 (x+y)+1,000z

where:
x is the fraction of total heat input derived from gaseous fossil fuel,
y is the fraction of total heat input derived from liquid fossil fuel, and
z is the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (b)(3) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414).)

§ 60.48a Compliance determination procedures and methods.

(a) The following procedures and reference methods are used to determine compliance with the standards for particulate matter under § 60.42a.

(1) Method 3 is used for gas analysis when applying method 5 or method 17.

(2) Method 5 is used for determining particulate matter emissions and associated moisture content. Method 17 may be used for stack gas temperatures less than 160 C (320 F).

(3) For Methods 5 or 17, Method 1 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(4) For Method 5, the probe and filter holder heating system in the sampling train is set to provide a gas temperature no greater than 160°C (32°F).

(5) For determination of particulate emissions, the oxygen or carbon-dioxide sample is obtained simultaneously with each run of Methods 5 or 17 by traversing the duct at the same sampling location. Method 1 is used for selection of the number of traverse points except that no more than 12 sample points are required.

(6) For each run using Methods 5 or 17, the emission rate expressed in ng/J heat input is determined using the oxygen or carbon-dioxide measurements and particulate matter measurements obtained under this section, the dry basis F_c-factor and the dry basis emission rate calculation procedure contained in Method 19 (Appendix A).

(7) Prior to the Administrator's issuance of a particulate matter reference method that does not experience sulfuric acid mist interference problems, particulate matter emissions may be sampled prior to a wet flue gas desulfurization system.

(b) The following procedures and methods are used to determine compliance with the sulfur dioxide standards under § 60.43a.

(1) Determine the percent of potential combustion concentration (percent PCC) emitted to the atmosphere as follows:

(i) *Fuel Pretreatment (% R_f):* Determine the percent reduction achieved by any fuel pretreatment using the procedures in Method 19 (Appendix A). Calculate the average percent reduction for fuel pretreatment on a quarterly basis using fuel analysis data. The determination of percent R_f to calculate the percent of potential combustion concentration emitted to the atmosphere is optional. For purposes of determining compliance with any percent reduction requirements under § 60.43a, any reduction in potential SO_2 emissions resulting from the following processes may be credited:

(A) Fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.),

(B) Coal pulverizers, and

(C) Bottom and flyash interactions.

(ii) *Sulfur Dioxide Control System (% R_g):* Determine the percent sulfur dioxide reduction achieved by any sulfur dioxide control system using emission rates measured before and after the control system, following the procedures in Method 19 (Appendix A); or, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19 (Appendix A). When the "as fired" fuel monitor is used, the percent reduction is calculated using the average emission rate from the sulfur dioxide control device and the average SO_2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(iii) *Overall percent reduction (% R_o):* Determine the overall percent reduction using the results obtained in paragraphs (b)(1) (i) and (ii) of this section following the procedures in Method 19 (Appendix A). Results are calculated for each 30-day period using the quarterly average percent sulfur reduction determined for fuel pretreatment from the previous quarter and the sulfur dioxide reduction achieved by a sulfur dioxide control system for each 30-day period in the current quarter.

(iv) *Percent emitted (% PCC):* Calculate the percent of potential combustion concentration emitted to the atmosphere using the following equation: Percent PCC = 100 − Percent R_o

(2) Determine the sulfur dioxide emission rates following the procedures in Method 19 (Appendix A).

(c) The procedures and methods outlined in Method 19 (Appendix A) are used in conjunction with the 30-day nitrogen-oxides emission data collected under § 60.47a to determine compliance with the applicable nitrogen oxides standard under § 60.44.

(d) Electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19 (Appendix A). The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 (Appendix A) calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

§ 60.49a Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, and particulate matter emissions, the performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or dilutent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_x only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by § 60.47a is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of § 60.46a(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (E_o^*) and the upper confidence limit for the mean inlet emission rate (E_i^*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o^*) and the allowable emission rate (E_{std}) as applicable.

(d) If any standards under § 60.43a are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under § 60.46a(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the sulfur dioxide emission standard under § 60.43a is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the

provisions of § 60.48a and Method 19 (Appendix A); and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(h) For the purposes of the reports required under § 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under § 60.42a(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(i) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414).)

4. Appendix A to part 60 is amended by adding new reference Method 19 as follows:

Appendix A—Reference Methods

* * * * *

Method 19. Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide and Nitrogen Oxides Emission Rates From Electric Utility Steam Generators

1. *Principle and Applicability*

1.1 *Principle.*

1.1.1 Fuel samples from before and after fuel pretreatment systems are collected and analyzed for sulfur and heat content, and the percent sulfur dioxide (ng/Joule, lb/million Btu) reduction is calculated on a dry basis. (Optional Procedure.)

1.1.2 Sulfur dioxide and oxygen or carbon dioxide concentration data obtained from sampling emissions upstream and downstream of sulfur dioxide control devices are used to calculate sulfur dioxide removal efficiencies. (Minimum Requirement.) As an alternative to sulfur dioxide monitoring upstream of sulfur dioxide control devices, fuel samples may be collected in an as-fired condition and analyzed for sulfur and heat content. (Optional Procedure.)

1.1.3 An overall sulfur dioxide emission reduction efficiency is calculated from the efficiency of fuel pretreatment systems and the efficiency of sulfur dioxide control devices.

1.1.4 Particulate, sulfur dioxide, nitrogen oxides, and oxygen or carbon dioxide concentration data obtained from sampling emissions downstream from sulfur dioxide control devices are used along with F factors to calculate particulate, sulfur dioxide, and nitrogen oxides emission rates. F factors are values relating combustion gas volume to the heat content of fuels.

1.2 *Applicability.* This method is applicable for determining sulfur removal efficiencies of fuel pretreatment and sulfur dioxide control devices and the overall reduction of potential sulfur dioxide emissions from electric utility steam generators. This method is also applicable for the determination of particulate, sulfur dioxide, and nitrogen oxides emission rates.

2. *Determination of Sulfur Dioxide Removal Efficiency of Fuel Pretreatment Systems*

2.1 *Solid Fossil Fuel.*

2.1.1 *Sample Increment Collection.* Use ASTM D 2234 [1], Type I, conditions A, B, or C, and systematic spacing. Determine the number and weight of increments required per gross sample representing each coal lot according to Table 2 or Paragraph 7.1.5.2 of ASTM D 2234 [1]. Collect one gross sample for each raw coal lot and one gross sample for each product coal lot.

2.1.2 *ASTM Lot Size.* For the purpose of Section 2.1.1, the product coal lot size is defined as the weight of product coal produced from one type of raw coal. The raw coal lot size is the weight of raw coal used to produce one product coal lot. Typically, the lot size is the weight of coal processsed in a 1-day (24 hours) period. If more than one type of coal is treated and produced in 1 day, then gross samples must be collected and analyzed for each type of coal. A coal lot size equaling the 90-day quarterly fuel quantity for a specific power plant may be used if representative sampling can be conducted for the raw coal and product coal.

Note.—Alternate definitions of fuel lot sizes may be specified subject to prior approval of the Administrator.

2.1.3 *Gross Sample Analysis.* Determine the percent sulfur content (%S) and gross calorific value (GCV) of the solid fuel on a dry basis for each gross sample. Use ASTM 2013 [1] for sample preparation, ASTM D 3177 [1] for sulfur analysis, and ASTM D 3173 [1] for moisture analysis. Use ASTM D 3176 [1] for gross calorific value determination.

2.2 *Liquid Fossil Fuel.*

2.2.1 *Sample Collection.* Use ASTM D 270 [1] following the practices outlined for continuous sampling for each gross sample representing each fuel lot.

2.2.2 *Lot Size.* For the purposes of Section 2.2.1, the weight of product fuel from one pretreatment facility and intended as one shipment (ship load, barge load, etc.) is defined as one product fuel lot. The weight of each crude liquid fuel type used to produce one product fuel lot is defined as one inlet fuel lot.

Note.— Alternate definitions of fuel lot sizes may be specified subject to prior approval of the Administrator.

Note.— For the purposes of this method, raw or inlet fuel (coal or oil) is defined as the fuel delivered to the desulfurization pretreatment facility or to the steam generating plant. For pretreated oil the input oil to the oil desulfurization process (e.g. hydrotreatment emitted) is sampled.

2.2.3 *Sample Analysis.* Determine the percent sulfur content (%S) and gross calorific value (GCV). Use ASTMD 240 [1] for the sample analysis. This value can be assumed to be on a dry basis.

[1] Use the most recent revision or designation of the ASTM procedure specified.

[1] Use the most recent revision or designation of the ASTM procedure specified.

2.3 *Calculation of Sulfur Dioxide Removal Efficiency Due to Fuel Pretreatment.* Calculate the percent sulfur dioxide reduction due to fuel pretreatment using the following equation:

$$\%R_f = 100\left[1 - \frac{\%S_o/GCV_o}{\%S_i/GCV_i}\right]$$

Where:

$\%R_f$ = Sulfur dioxide removal efficiency due pretreatment; percent.

$\%S_o$ = Sulfur content of the product fuel lot on a dry basis; weight percent.

$\%S_i$ = Sulfur content of the inlet fuel lot on a dry basis; weight percent.

GCV_o = Gross calorific value for the outlet fuel lot on a dry basis; kJ/kg (Btu/lb).

GCV_i = Gross calorific value for the inlet fuel lot on a dry basis; kJ/kg (Btu/lb).

Note.—If more than one fuel type is used to produce the product fuel, use the following equation to calculate the sulfur contents per unit of heat content of the total fuel lot, %S/GCV:

$$\%S/GCV = \sum_{k=1}^{n} Y_k(\%S_k/GCV_k)$$

Where:

Y_k = The fraction of total mass input derived from each type, k, of fuel.

$\%S_k$ = Sulfur content of each fuel type, k, on a dry basis; weight percent.

GCV_k = Gross calorific value for each fuel type, k, on a dry basis; kJ/kg (Btu/lb).

n = The number of different types of fuels.

3. *Determination of Sulfur Removal Efficiency of the Sulfur Dioxide Control Device*

3.1 *Sampling.* Determine SO_2 emission rates at the inlet and outlet of the sulfur dioxide control system according to methods specified in the applicable subpart of the regulations and the procedures specified in Section 5. The inlet sulfur dioxide emission rate may be determined through fuel analysis (Optional, see Section 3.3.)

3.2. *Calculation.* Calculate the percent removal efficiency using the following equation:

$$\%R_{g(m)} = 100 \times \left(1.0 - \frac{E_{SO_2 o}}{E_{SO_2 i}}\right)$$

Where:

$\%R_g$ = Sulfur dioxide removal efficiency of the sulfur dioxide control system using inlet and outlet monitoring data; percent.

$E_{SO_2 o}$ = Sulfur dioxide emission rate from the outlet of the sulfur dioxide control system; ng/J (lb/million Btu).

$E_{SO_2 i}$ = Sulfur dioxide emission rate to the outlet of the sulfur dioxide control system; ng/J (lb/million Btu).

3.3 *As-fired Fuel Analysis (Optional Procedure).* If the owner or operator of an electric utility steam generator chooses to determine the sulfur dioxide imput rate at the inlet to the sulfur dioxide control device through an as-fired fuel analysis in lieu of data from a sulfur dioxide control system inlet gas monitor, fuel samples must be collected in accordance with applicable paragraph in Section 2. The sampling can be conducted upstream of any fuel processing, e.g., plant coal pulverization. For the purposes of this section, a fuel lot size is defined as the weight of fuel consumed in 1 day (24 hours) and is directly related to the exhaust gas monitoring data at the outlet of the sulfur dioxide control system.

3.3.1 *Fuel Analysis.* Fuel samples must be analyzed for sulfur content and gross calorific value. The ASTM procedures for determining sulfur content are defined in the applicable paragraphs of Section 2.

3.3.2 *Calculation of Sulfur Dioxide Input Rate.* The sulfur dioxide imput rate determined from fuel analysis is calculated by:

$$I_s = \frac{2.0(\%S_f)}{GCV} \times 10^7 \quad \text{for S. I. units.}$$

$$I_s = \frac{2.0(\%S_f)}{GCV} \times 10^4 \quad \text{for English units.}$$

Where:

I_s = Sulfur dioxide input rate from as-fired fuel analysis, ng/J (lb/million Btu).

$\%S_f$ = Sulfur content of as-fired fuel, on a dry basis; weight percent.

GCV = Gross calorific value for as-fired fuel, on a dry basis; kJ/kg (Btu/lb).

3.3.3 *Calculation of Sulfur Dioxide Emission Reduction Using As-fired Fuel Analysis.* The sulfur dioxide emission reduction efficiency is calculated using the sulfur imput rate from paragraph 3.3.2 and the sulfur dioxide emission rate, E_{SO_2}, determined in the applicable paragraph of Section 5.3. The equation for sulfur dioxide emission reduction efficiency is:

$$\%R_{g(f)} = 100 \times \left(1.0 - \frac{E_{SO_2}}{I_s}\right)$$

Where:

$\%R_{g(f)}$ = Sulfur dioxide removal efficiency of the sulfur dioxide control system using as-fired fuel analysis data; percent.

E_{SO_2} = Sulfur dioxide emission rate from sulfur dioxide control system; ng/J (lb/million Btu).

I_s = Sulfur dioxide input rate from as-fired fuel analysis; ng/J (lb/million Btu).

4. *Calculation of Overall Reduction in Potential Sulfur Dioxide Emission*

4.1 The overall percent sulfur dioxide reduction calculation uses the sulfur dioxide concentration at the inlet to the sulfur dioxide control device as the base value. Any sulfur reduction realized through fuel cleaning is introduced into the equation as an average percent reduction, $\%R_f$.

4.2 Calculate the overall percent sulfur reduction as:

$$\%R_o = 100\left[1.0 - \left(1.0 - \frac{\%R_f}{100}\right)\left(1.0 - \frac{\%R_g}{100}\right)\right]$$

Where:

$\%R_o$ = Overall sulfur dioxide reduction; percent.

$\%R_f$ = Sulfur dioxide removal efficiency of fuel pretreatment from Section 2; percent. Refer to applicable subpart for definition of applicable averaging period.

$\%R_g$ = Sulfur dioxide removal efficiency of sulfur dioxide control device either O_2 or CO_2 - based calculation or calculated from fuel analysis and emission data, from Section 3; percent. Refer to applicable subpart for definition of applicable averaging period.

5. *Calculation of Particulate, Sulfur Dioxide, and Nitrogen Oxides Emission Rates*

5.1 *Sampling.* Use the outlet SO_2 or O_2 or CO_2 concentrations data obtained in Section 3.1. Determine the particulate, NO_x, and O_2 or CO_2 concentrations according to methods specified in an applicable subpart of the regulations.

5.2 *Determination of an F Factor.* Select an average F factor (Section 5.2.1) or calculate an applicable F factor (Section 5.2.2.). If combined fuels are fired, the selected or calculated F factors are prorated using the procedures in Section 5.2.3. F factors are ratios of the gas volume released during combustion of a fuel divided by the heat content of the fuel. A dry F factor (F_d) is the ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted; a wet F factor (F_w) is the ratio of the volume of wet flue gases generated to the calorific value of the fuel combusted; and the carbon F factor (F_c) is the ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted. When pollutant and oxygen concentrations have been determined in Section 5.1, wet or dry F factors are used. (F_w) factors and associated emission calculation procedures are not applicable and may not be used after wet scrubbers; (F_c) or (F_d) factors and associated emission calculation procedures are used after wet scrubbers.) When pollutant and carbon dioxide concentrations have been determined in Section 5.1, F_c factors are used.

5.2.1 *Average F Factors.* Table 1 shows average F_d, F_w, and F_c factors (scm/J, scf/million Btu) determined for commonly used fuels. For fuels not listed in Table 1, the F factors are calculated according to the procedures outlined in Section 5.2.2 of this section.

5.2.2 *Calculating an F Factor.* If the fuel burned is not listed in Table 1 or if the owner or operator chooses to determine an F factor rather than use the tabulated data, F factors are calculated using the equations below. The sampling and analysis procedures followed in obtaining data for these calculations are subject to the approval of the Administrator and the Administrator should be consulted prior to data collection.

For SI Units:

$$F_d = \frac{227.0(\%H) + 95.7(\%C) + 35.4(\%S) + 8.6(\%N) - 28.5(\%O)}{GCV}$$

$$F_w = \frac{347.4(\%H)+95.7(\%C)+35.4(\%S)+8.6(\%N)-28.5(\%O)+13.0(\%H_2O)^{**}}{GCV_w}$$

$$F_c = \frac{20.0(\%C)}{GCV}$$

For English Units:

$$F_d = \frac{10^6[5.57(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)]}{GCV}$$

$$F_w = \frac{10^6[5.57(\%H)+1.53(\%C)+0.57(\%S)+0.14(\%N)-0.46(\%O)+0.21(\%H_2O)^{**}]}{GCV_w}$$

$$F_c = \frac{10^6[0.321(\%C)]}{GCV}$$

** The $\%H_2O$ term may be omitted if %H and %O include the unavailable hydrogen and oxygen in the form of H_2O.

Where:

F_d, F_w, and F_c have the units of scm/J, or scf/million Btu; %H, %C, %S, %N, %O, and $\%H_2O$ are the concentrations by weight (expressed in percent) of hydrogen, carbon, sulfur, nitrogen, oxygen, and water from an ultimate analysis of the fuel; and GCV is the gross calorific value of the fuel in kJ/kg or Btu/lb and consistent with the ultimate analysis. Follow ASTM D 2015* for solid fuels, D 240* for liquid fuels, and D 1826* for gaseous fuels as applicable in determining GCV.

5.2.3 *Combined Fuel Firing F Factor.* For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F_d, F_w, or F_c factors determined by Sections 5.2.1 or 5.2.2 of this section shall be prorated in accordance with applicable formula as follows:

$$F_d = \sum_{k=1}^{n} x_k F_{dk} \quad \text{or}$$

$$F_w = \sum_{k=1}^{n} x_k F_{wk} \quad \text{or}$$

$$F_c = \sum_{k=1}^{n} x_k F_{ck}$$

Where:

x_k = The fraction of total heat input derived from each type of fuel, K.

n = The number of fuels being burned in combination.

5.3 *Calculation of Emission Rate.* Select from the following paragraphs the applicable calculation procedure and calculate the particulate, SO_2, and NO_x emission rate. The values in the equations are defined as:

E = Pollutant emission rate, ng/J (lb/million Btu).

C = Pollutant concentration, ng/scm (lb/scf).

Note.—It is necessary in some cases to convert measured concentration units to other units for these calculations.

Use the following table for such conversions:

Conversion Factors for Concentration

From—	To—	Multiply by—
g/scm	ng/scm	10^9
mg/scm	ng/scm	10^6
lb/scf	ng/scm	1.602×10^{12}
ppm(SO_2)	ng/scm	2.660×10^6
ppm(NO_2)	ng/scm	1.912×10^6
ppm/(SO_2)	lb/scf	1.660×10^{-7}
ppm/(NO_2)	lb/scf	1.194×10^{-7}

5.3.1 *Oxygen-Based F Factor Procedure.*

5.3.1.1 *Dry Basis.* When both percent oxygen ($\%O_{2d}$) and the pollutant concentration (C_d) are measured in the flue gas on a dry basis, the following equation is applicable:

$$E = C_d F_d \left[\frac{20.9}{20.9 - \%O_{2d}}\right]$$

5.3.1.2 *Wet Basis.* When both the percent oxygen ($\%O_{2w}$) and the pollutant concentration (C_w) are measured in the flue gas on a wet basis, the following equations are applicable: (Note: F_w factors are not applicable after wet scrubbers.)

(a) $$E = C_w F_w \left[\frac{20.9}{20.9(1 - B_{wa}) - \%O_{2w}}\right]$$

Where:

B_{wa} = Proportion by volume of water vapor in the ambient air.

In lieu of actual measurement, B_{wa} may be estimated as follows:

Note.—The following estimating factors are selected to assure that any negative error introduced in the term:

$$\left(\frac{20.9}{20.9(1 - B_{wa}) - \%O_{2ws}}\right)$$

will not be larger than −1.5 percent. However, positive errors, or overestimation of emissions, of as much as 5 percent may be introduced depending upon the geographic location of the facility and the associated range of ambient mositure.

(i) $B_{wa} = 0.027$. This factor may be used as a constant value at any location.

(ii) B_{wa} = Highest monthly average of B_{wa} which occurred within a calendar year at the nearest Weather Service Station.

(iii) B_{wa} = Highest daily average of B_{wa} which occurred within a calendar month at the nearest Weather Service Station, calculated from the data for the past 3 years. This factor shall be calculated for each month and may be used as an estimating factor for the respective calendar month.

(b) $$E = C_w F_d \left[\frac{20.9}{20.9(1 - B_{ws}) - \%O_{2w}}\right]$$

Where:

B_{ws} = Proportion by volume of water vapor in the stack gas.

5.3.1.3 *Dry/Wet Basis.* When the pollutant concentration (C_w) is measured on a wet basis and the oxygen concentration ($\%O_{2d}$) or measured on a dry basis, the following equation is applicable:

$$E = \left[\frac{C_w F_d}{(1 - B_{ws})}\right] \left[\frac{20.9}{20.9 - \%O_{2d}}\right]$$

When the pollutant concentration (C_d) is measured on a dry basis and the oxygen concentration ($\%O_{2d}$) is measured on a wet basis, the following equation is applicable:

$$E = C_d F_d \frac{20.9}{20.9 - \left(\frac{\%O_{2w}}{(1 - B_{ws})}\right)}$$

5.3.2 *Carbon Dioxide-Based F Factor Procedure.*

5.3.2.1 *Dry Basis.* When both the percent carbon dioxide ($\%CO_{2d}$) and the pollutant concentration (C_d) are measured in the flue gas on a dry basis, the following equation is applicable:

$$E = C_d F_c \left(\frac{100}{\%CO_{2d}}\right)$$

5.3.2.2 *Wet Basis.* When both the percent carbon dioxide ($\%CO_{2w}$) and the pollutant concentration (C_w) are measured on a wet basis, the following equation is applicable:

$$E = C_w F_c \left(\frac{100}{\%CO_{2w}}\right)$$

5.3.2.3 *Dry/Wet Basis.* When the pollutant concentration (C_w) is measured on a wet basis and the percent carbon dioxide ($\%CO_{2d}$) is measured on a dry basis, the following equation is applicable:

$$E = \left[\frac{C_w F_c}{(1 - B_{ws})}\right] \left[\frac{100}{\%CO_{2d}}\right]$$

When the pollutant concentration (C_d) is measured on a dry basis and the precent carbon dioxide ($\%CO_{2w}$) is measured on a wet basis, the following equation is applicable:

$$E = C_d (1 - B_{ws}) F_c \left(\frac{100}{\%CO_{2w}}\right)$$

5.4 *Calculation of Emission Rate from Combined Cycle-Gas Turbine Systems.* For gas turbine-steam generator combined cycle systems, the emissions from supplemental fuel fired to the steam generator or the percentage reduction in potential (SO_2) emissions cannot be determined directly. Using measurements from the gas turbine exhaust (performance test, subpart GG) and the combined exhaust gases from the steam generator, calculate the emission rates for these two points following the appropriate paragraphs in Section 5.3.

Note.—F_w factors shall not be used to determine emission rates from gas turbines because of the injection of steam nor to calculate emission rates after wet scrubbers; F_d or F_c factor and associated calculation procedures are used to combine effluent emissions according to the procedure in Paragraph 5.2.3.

The emission rate from the steam generator is calculated as:

4. *Calculation of Overall Reduction in Potential Sulfur Dioxide Emission*

4.1 The overall percent sulfur dioxide reduction calculation uses the sulfur dioxide concentration at the inlet to the sulfur dioxide control device as the base value. Any sulfur reduction realized through fuel cleaning is introduced into the equation as an average percent reduction, $\%R_f$.

4.2 Calculate the overall percent sulfur reduction as:

$$\%R_o = 100\left[1.0 - \left(1.0 - \frac{\%R_f}{100}\right)\left(1.0 - \frac{\%R_g}{100}\right)\right]$$

Where:

$\%R_o$ = Overall sulfur dioxide reduction; percent.

$\%R_f$ = Sulfur dioxide removal efficiency of fuel pretreatment from Section 2; percent. Refer to applicable subpart for definition of applicable averaging period.

$\%R_g$ = Sulfur dioxide removal efficiency of sulfur dioxide control device either O_2 or CO_2 - based calculation or calculated from fuel analysis and emission data, from Section 3; percent. Refer to applicable subpart for definition of applicable averaging period.

5. *Calculation of Particulate, Sulfur Dioxide, and Nitrogen Oxides Emission Rates*

5.1 *Sampling.* Use the outlet SO_2 or O_2 or CO_2 concentrations data obtained in Section 3.1. Determine the particulate, NO_x, and O_2 or CO_2 concentrations according to methods specified in an applicable subpart of the regulations.

5.2 *Determination of an F Factor.* Select an average F factor (Section 5.2.1) or calculate an applicable F factor (Section 5.2.2). If combined fuels are fired, the selected or calculated F factors are prorated using the procedures in Section 5.2.3. F factors are ratios of the gas volume released during combustion of a fuel divided by the heat content of the fuel. A dry F factor (F_d) is the ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted; a wet F factor (F_w) is the ratio of the volume of wet flue gases generated to the calorific value of the fuel combusted; and the carbon F factor (F_c) is the ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted. When pollutant and oxygen concentrations have been determined in Section 5.1, wet or dry F factors are used. (F_w) factors and associated emission calculation procedures are not applicable and may not be used after wet scrubbers; (F_c) or (F_d) factors and associated emission calculation procedures are used after wet scrubbers.) When pollutant and carbon dioxide concentrations have been determined in Section 5.1, F_c factors are used.

5.2.1 *Average F Factors.* Table 1 shows average F_d, F_w, and F_c factors (scm/J, scf/million Btu) determined for commonly used fuels. For fuels not listed in Table 1, the F factors are calculated according to the procedures outlined in Section 5.2.2 of this section.

5.2.2 *Calculating an F Factor.* If the fuel burned is not listed in Table 1 or if the owner or operator chooses to determine an F factor rather than use the tabulated data, F factors are calculated using the equations below. The sampling and analysis procedures followed in obtaining data for these calculations are subject to the approval of the Administrator and the Administrator should be consulted prior to data collection.

For SI Units:

$$F_d = \frac{227.0(\%H) + 95.7(\%C) + 35.4(\%S) + 8.6(\%N) - 28.5(\%O)}{GCV}$$

$$F_w = \frac{347.4(\%H)+95.7(\%C)+35.4(\%S)+8.6(\%N)-28.5(\%O)+13.0(\%H_2O)^{**}}{GCV_w}$$

$$F_c = \frac{20.0(\%C)}{GCV}$$

For English Units:

$$F_d = \frac{10^6[5.57(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)]}{GCV}$$

$$F_w = \frac{10^6[5.57(\%H)+1.53(\%C)+0.57(\%S)+0.14(\%N)-0.46(\%O)+0.21(\%H_2O)^{**}]}{GCV_w}$$

$$F_c = \frac{10^6[0.321(\%C)]}{GCV}$$

**The $\%H_2O$ term may be omitted if %H and %O include the unavailable hydrogen and oxygen in the form of H_2O.

$$E_{sg} = \frac{E_c - X_{gt} E_{gt}}{X_{sg}}$$

Where:

E_{sg} = Pollutant emission rate from steam generator effluent, ng/J (lb/million Btu).
E_c = Pollutant emission rate in combined cycle effluent; ng/J (lb/million Btu).
E_{gt} = Pollutant emission rate from gas turbine effluent; ng/J (lb/million Btu).
X_{sg} = Fraction of total heat input from supplemental fuel fired to the steam generator.
X_{gt} = Fraction of total heat input from gas turbine exhaust gases.

Note.—The total heat input to the steam generator is the sum of the heat input from supplemental fuel fired to the steam generator and the heat input to the steam generator from the exhaust gases from the gas turbine.

5.5 *Effect of Wet Scrubber Exhaust, Direct-Fired Reheat Fuel Burning.* Some wet scrubber systems require that the temperature of the exhaust gas be raised above the moisture dew-point prior to the gas entering the stack. One method used to accomplish this is directfiring of an auxiliary burner into the exhaust gas. The heat required for such burners is from 1 to 2 percent of total heat input of the steam generating plant. The effect of this fuel burning on the exhaust gas components will be less than ±1.0 percent and will have a similar effect on emission rate calculations. Because of this small effect, a determination of effluent gas constituents from direct-fired reheat burners for correction of stack gas concentrations is not necessary.

Table 19-1.—*F Factors for Various fuels*[a]

Fuel type	F_d dscm/J	F_d dscf/10^6 Btu	F_w wscm/J	F_w wscf/10^6 Btu	F_c scm/J	F_c scf/10^6 Btu
Coal:						
Anthracite[a]	2.71×10^{-7}	(10100)	2.83×10^{-7}	(10540)	0.530×10^{-7}	(1970)
Bituminous[a]	2.63×10^{-7}	(9780)	2.86×10^{-7}	(10640)	0.484×10^{-7}	(1800)
Lignite	2.65×10^{-7}	(9860)	3.21×10^{-7}	(11950)	0.513×10^{-7}	(1910)
Oil[b]	2.47×10^{-7}	(9190)	2.77×10^{-7}	(10320)	0.383×10^{-7}	(1420)
Gas:						
Natural	2.43×10^{-7}	(8710)	2.85×10^{-7}	(10610)	0.287×10^{-7}	(1040)
Propane	2.34×10^{-7}	(8710)	2.74×10^{-7}	(10200)	0.321×10^{-7}	(1190)
Butane	2.34×10^{-7}	(8710)	2.79×10^{-7}	(10390)	0.337×10^{-7}	(1250)
Wood	2.48×10^{-7}	(9240)			0.492×10^{-7}	(1830)
Wood Bark	2.58×10^{-7}	(9600)			0.497×10^{-7}	(1850)

[a] As classified according to ASTM D 388-66.
[b] Crude, residual, or distillate.
[c] Determined at standard conditions: 20° C (68° F) and 760 mm Hg (29.92 in. Hg).

6. *Calculation of Confidence Limits for Inlet and Outlet Monitoring Data*

6.1 *Mean Emission Rates.* Calculate the mean emission rates using hourly averages in ng/J (lb/million Btu) for SO_2 and NO_x outlet data and, if applicable, SO_2 inlet data using the following equations:

$$E_o = \frac{\Sigma x_o}{n_o}.$$

$$E_i = \frac{\Sigma x_i}{n_i}$$

Where:

E_o = Mean outlet emission rate; ng/J (lb/million Btu).
E_i = Mean inlet emission rate; ng/J (lb/million Btu).
x_o = Hourly average outlet emission rate; ng/J (lb/million Btu).
x_i = Hourly average in let emission rate; ng/j (lb/million Btu).
n_o = Number of outlet hourly averages available for the reporting period.
n_i = Number of inlet hourly averages available for reporting period.

6.2 *Standard Deviation of Hourly Emission Rates.* Calculate the standard deviation of the available outlet hourly average emission rates for SO_2 and NO_x and, if applicable, the available inlet hourly average emission rates for SO_2 using the following equations:

$$s_o = \left(\sqrt{\frac{1}{n_o} - \frac{1}{720}}\right)\left(\sqrt{\frac{\Sigma (E_o - x_o)^2}{n_o - 1}}\right)$$

$$s_i = \left(\sqrt{\frac{1}{n_i} - \frac{1}{720}}\right)\left(\sqrt{\frac{\Sigma (E_i - x_i)^2}{n_i - 1}}\right)$$

Where:

s_o = Standard deviation of the average outlet hourly average emission rates for the reporting period; ng/J (lb/million Btu).
s_i = Standard deviation of the average inlet hourly average emission rates for the reporting period; ng/J (lb/million Btu).

6.3 *Confidence Limits.* Calculate the lower confidence limit for the mean outlet emission rates for SO_2 and NO_x and, if applicable, the upper confidence limit for the mean inlet emission rate for SO_2 using the following equations:

$$E_o^* = E_o - t_{.9,n} s_o$$
$$E_i^* = E_i + t_{.9,n} s_i$$

Where:

E_o^* = The lower confidence limit for the mean outlet emission rates; ng/J (lb/million Btu).
E_i^* = The upper confidence limit for the mean inlet emission rate; ng/J (lb/million Btu).
$t_{.9,n}$ = Values shown below for the indicated number of available data points (n):

n	Values for $t_{.9,n}$
2	6.31
3	2.42
4	2.35
5	2 13
6	2.02
7	1.94
8	1.89
9	1.86
10	1.83
11	1.81
12-16	1.77
17-21	1.73
22-26	1.71
27-31	1.70
32-51	1.68
52-91	1.67
92-151	1.66
152 or more	1.65

The values of this table are corrected for n-1 degrees of freedom. Use n equal to the number of hourly average data points.

7. *Calculation to Demonstrate Compliance When Available Monitoring Data Are Less Than the Required Minimum*

7.1 *Determine Potential Combustion Concentration (PCC) for SO_2.*

7.1.1 When the removal efficiency due to fuel pretreatment (% R_f) is included in the overall reduction in potential sulfur dioxide emissions (% R_o) and the "as-fired" fuel analysis is not used, the potential combustion concentration (PCC) is determined as follows:

$$PCC = E_i^* + 2\left(\frac{\%\ S_i}{GCV_i} - \frac{\%\ S_o}{GCV_o}\right) 10^7;\ ng/J$$

$$PCC = E_i^* + 2\left(\frac{\%\ S_i}{GCV_i} - \frac{\%\ S_o}{GCV_o}\right) 10^4;\ lb/million\ Btu.$$

Where:

$\left(\frac{\%\ S_i}{GCV_i} - \frac{\%\ S_o}{GCV_o}\right)$ = Potential emissions removed by the pretreatment process, using the fuel parameters defined in section 2.3; ng/J (lb/million Btu).

7.1.2 When the "as-fired" fuel analysis is used and the removal efficiency due to fuel pretreatment (% R_f) is not included in the overall reduction in potential sulfur dioxide emissions (% R_o), the potential combustion concentration (PCC) is determined as follows:

$PCC = I_s$

Where:

I_s = The sulfur dioxide input rate as defined in section 3.3

7.1.3 When the "as-fired" fuel analysis is used and the removal efficiency due to fuel pretreatment (% R_f) is included in the overall reduction (% R_o), the potential combustion concentration (PCC) is determined as follows:

$$PCC = I_s + 2\left(\frac{\%\ S_f}{GCV_f} - \frac{\%\ S_o}{GCV_o}\right)10^7;\ ng/J$$

$$PCC = I_s + 2\left(\frac{\%\ S_f}{GCV_f} - \frac{\%\ S_o}{GCV_o}\right)10^4;\ lb/million\ Btu.$$

7.1.4 When inlet monitoring data are used and the removal efficiency due to fuel pretreatment (% R_f) is not included in the overall reduction in potential sulfur dioxide emissions (% R_o), the potential combustion concentration (PCC) is determined as follows:

$PCC = E_i^*$

Where:

E_i^* = The upper confidence limit of the mean inlet emission rate, as determined in section 6.3.

7.2 *Determine Allowable Emission Rates (E_{std}).*

7.2.1 *NO_x.* Use the allowable emission rates for NO_x as directly defined by the applicable standard in terms of ng/J (lb/million Btu).

7.2.2 *SO_2.* Use the potential combustion concentration (PCC) for SO_2 as determined in section 7.1, to determine the applicable emission standard. If the applicable standard is an allowable emission rate in ng/J (lb/million Btu), the allowable emission rate is used as E_{std}. If the applicable standard is an allowable percent emission, calculate the allowable emission rate (E_{std}) using the following equation:

$E_{std} = \%\ PCC/100$

Where:

% PCC = Allowable percent emission as defined by the applicable standard; percent.

7.3 *Calculate E_o^*/E_{std}.* To determine compliance for the reporting period calculate the ratio:

E_o^*/E_{std}

Where:

E_o^* = The lower confidence limit for the mean outlet emission rates, as defined in section 6.3; ng/J (lb/million Btu).

E_{std} = Allowable emission rate as defined in section 7.2; ng/J (lb/million Btu).

If E_o^*/E_{std} is equal to or less than 1.0, the facility is in compliance; if E_o^*/E_{std} is greater than 1.0, the facility is not in compliance for the reporting period.

[FR Doc. 79-17607 Filed 6-8-79; 8:45 am]
BILLING CODE 6560-01-M

99

40 CFR Part 60

[FRL 1276-3]

Priority List and Additions to the List of Categories of Stationary Sources

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This action contains EPA's promulgated list of major source categories for which standards of performance for new stationary sources are to be promulgated by August 1982. The Clean Air Act Amendments of 1977 specify that the Administrator publish a list of the categories of major stationary sources which have not been previously listed as source categories for which standards of performance will be established. The promulgated list implements the Clean Air Act and reflects the Administrator's determination that, based on preliminary assessments, emissions from the listed source categories contribute significantly to air pollution. The intended effect of this promulgation is to identify major source categories for which standards of performance are to be promulgated. The standards would apply only to new or modified stationary sources of air pollution.

EFFECTIVE DATE: August 21, 1979.

ADDRESSES: The background document for the promulgated priority list may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number 919-541-2777. Please refer to "Revised Prioritized List of Source Categories for New Source Performance Standards," EPA-450/3-79-023. The prioritization methodology is explained in the background document for the proposed priority list. This document, "Priorities for New Source Performance Standards under the Clean Air Act Amendments of 1977," EPA-450/3-78-019, can also be obtained from the Research Triangle Park EPA Library. Copies of all comment letters received from interested persons participating in this rulemaking, a summary of these comments, and a summary of the September 29, 1978, public hearing are available for inspection and copying during normal business hours at EPA's Public Information Reference Unit, Room 2922 (EPA Library), 401 M Street, SW., Washington, DC.

FOR FURTHER INFORMATION CONTACT: Gary D. McCutchen, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone number (919) 541-5421.

SUPPLEMENTARY INFORMATION: On August 31, 1978 (43 FR 38872), EPA proposed a priority list of major source catagories for which standards of performance would be promulgated by August 1982, and invited public comment on the list and the methodology used to prioritize the source categories. Promulgation of this list is required by section 111(f) of the Clean Air Act as amended August 7, 1977. The significant comments that were received during the public comment period, including those made at a September 29, 1978, public hearing, have been carefully reviewed and considered and, where determined by the Administrator to be appropriate, changes have been included in this notice of final rulemaking.

Background

The program to establish standards of performance for new stationary sources (also called New Source Performance Standards or NSPS) began on December 1970, when the Clean Air Act was signed into law. Authorized under section 111 of the Act, NSPS were to require the best control system (considering cost) for new facilities, and were intended to complement the other air quality management approaches authorized by the 1970 Act. A total of 27 source categories are regulated by NSPS, with NSPS for an additional 25 source categories under development.

During the 1977 hearings on the Clean Air Act, Congress received testimony on the need for more rapid development of NSPS. There was concern that not all sources which had the potential to endanger public health or welfare were controlled by NSPS and that the potential existed for "environmental blackmail" from source categories not subject to NSPS. These concerns were reflected in the Clean Air Act Amendments of 1977, specifically in section 111(f).

Section 111(f) requires that the Administrator publish a list of major stationary sources of air pollution not listed, as of August 7, 1977, under section 111(b)(1)(A), which in effect meant those sources for which NSPS had not yet been proposed or promulgated. Before promulgating this list, the Administrator was to provide notice of and opportunity for a public hearing and consult with Governors and State air pollution control agencies. In developing priorities, section 111(f) specifies that the Administrator consider (1) the quantity of emissions from each source category, (2) the extent to which each pollutant endangers public health or welfare, and (3) the mobility and competitive nature of each stationary source category, e.g., the capability of a new or existing source to locate in areas with less stringent air pollution control regulations. Governors may at any time submit applications under section 111(g) to add major source categories to the list, add any source category to the list which may endanger public health or welfare, change the priority ranking, or revise promulgated NSPS.

Development of the Priority List

Development of the priority list was initiated by compiling data on a large number of source categories from literature resources. The data were first analyzed to determine major source categories, those categories for which an average size plant has the potential to emit 100 tons or more per year of any one pollutant. These major source categories were then subjected to a priority ranking procedure using the three criteria specified in section 111(f) of the Act.

The procedure used first ranks source categories on a pollutant by pollutant basis. This resulted in nine lists (one for each pollutant—volatile organic compounds (VOC), nitrogen oxides, particulate matter, sulfur dioxide, carbon monoxide, lead, fluorides, acid mist, and hydrogen sulfide) with each list ranked using the criteria in the Act. In this ranking, first priority was given to quantity of emissions, second priority to potential impact on health or welfare, and third priority to mobility. Thus, sources with the greatest growth rates and emission reduction potential were high on each list; sources with limited choice of location, low growth and small emission reduction potential were low on each list.

The nine lists were combined into one by selecting pollutant goals--a procedure which, in effect, assigned a relative priority to pollutants based upon the potential impact of NSPS. After the pollutant goals were selected, the final priority list was established through the selection of source categories which have maximum impact on attaining the selected goals. The effect of this procedure was to emphasize control of all criteria pollutants except carbon monoxide and to give carbon monoxide and non-criteria pollutants a lower priority.

In the background reports and in the preamble to the proposed priority list, the term "hydrocarbon" was used even though the emissions referred to were VOC which, unlike hydrocarbon compounds, can contain elements other than carbon and hydrogen. A VOC is defined by EPA as any organic compound that, when released to the atmosphere, can remain long enough to participate in photochemical reactions. Since VOC contribute to ambient levels of photochemical oxidants, they are considered a criteria pollutant.

The ranking of source categories on the list and the differentiation between major and minor sources was sensitive to the accuracy of the data utilized. The data base used to establish the priority list was obtained from a number of literature sources including EPA screening studies. However, screening studies were not available for all source categories. Therefore, if new information becomes available after promulgation of the list, the Administrator may delete from or add to the list in response to this new information.

Additional detail on the prioritization methodology, the input factors used, and the ranking of individual source categories is available in the two background documents (see "ADDRESSES").

Significance of Priority List

The promulgated list is essentially an advance notice of future standard development activity. It identifies major source categories and the approximate order in which NSPS development would be initiated. However, if further study indicates that an NSPS would have little or no effect on emissions, or that an NSPS would be impractical, a source category would be given a lower priority or removed from the list. Similarly, new information may increase the priority of a source category. The Administrator may also concurrently develop standards for sources which are not on the priority list, especially certain "minor" sources which, in aggregate, represent a large quantity of emissions.

The distinction between major and minor source categories is defined only for the purpose of determining NSPS priorities and should not be used to determine sources subject to New Source Review, which is conducted on a case-by-case basis. Moreover, some New Source Review programs, such as prevention of significant deterioration, have separate and distinct criteria for defining a major source (e.g., 100 tons per year potential for certain source types and 250 tons per year for others).

Identification of Source Categories

Two groups of sources in addition to minor sources are not included on the promulgated list. One group includes sources which could not be evaluated due to insufficient information. This lack of data suggests that these sources, which are identified in the background report, "Priorities for NSPS under the Clean Air Act of 1977," have not previously been regulated or studied and, therefore, are probably not major sources. Nevertheless, the Administrator will continue to investigate these sources and will consider development of NSPS for any which are identified as being significant sources of air pollution.

The second group of source categories not on the priority list consists of those listed under section 111(b)(1)(A) on or before August 7, 1977. These are.

Fossil-fuel-fired steam generators
Incinerators
Portland Cement Plants
Nitric Acid Plants
Sulfuric Acid Plants
Asphalt Concrete Plants
Petroleum Refineries
Storage Vessels for Petroleum Liquids
Secondary Lead Smelters
Secondary Brass and Bronze Ingot Production Plants
Iron and Steel Plants
Sewage Treatment Plants
Primary Copper Smelters
Primary Zinc Smelters
Primary Lead Smelters
Primary Aluminum Reduction Plants
Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants
Phosphate Fertilizer Industry: Superphosphoric Acid Plants
Phosphate Fertilizer Industry: Diammonium Phosphate Plants
Phosphate Fertilizer Industry: Triple Superphosphate Plants
Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities
Coal Preparation Plants
Ferroalloy Production Facilities
Steel Plants: Electric Arc Furnaces
Kraft Pulp Mills
Lime Plants
Grain Elevators

There are, however, some facilities (or subcategories) within these source categories for which NSPS have not been developed, but which may by themselves be significant sources of air pollution. A number of these facilities were evaluated as if they were separate source categories; three which rank high in priority are included on the promulgated list to indicate that the Administrator plans to develop standards for them: Petroleum refinery fugitive emissions, industrial fossil-fuel-fired steam generators, and non-municipal incinerators. In addition to these, the Administrator will continue to evaluate affected facilities within listed source categories and may from time to time develop NSPS for such facilities. The iron and steel industry provides an example of a category which is already listed (so does not appear on the priority list), but in which an active interest remains. Although the growth rate for new sintering capacity is presently very low, the Administrator is continuing to assess emission control and measurement technology with a view toward possible development of an NSPS for sintering plants at a later date. A project is also underway to update emission factors for all steelmaking processes, including fugitive emissions, in an effort to determine the relative significance of emissions from each process. In addition, byproduct coke ovens, nearly always associated with steel mills, are included on the priority list and are undergoing standard development studies.

There are some differences between the format of the list in the background report, "Revised Prioritized List of Source Categories for NSPS Promulgation" and the format of the list which appears here. These differences are primarily a result of aggregation of subcategories which had been subdivided for size classification and priority ranking analysis. Non-metallic mineral processing, for example, had been subdivided into nine subcategories for prioritization, eight of which were analyzed separately (stone, sand and gravel, clay, gypsum lime, borax, fluorspar, and phosphate rock mining) and one of which is considered a minor source (mica mining). EPA plans to study the entire non-metallic mineral processing industry at one time, since many of the processes and control techniques are similar. For this reason, the industry is identified by a single aggregated listing. This does not necessarily imply that a single standard would apply to all sources within the listed category. Rather, as described below in the case of the synthetic organic chemical manufacturing industry, the nature and scope of standards will be determined only after a detailed study of sources within the category.

In addition to the major sources, three source categories not identified as being major source categories have been added to the list: organic solvent cleaning, industrial surface coating of metal furniture, and lead acid battery manufacture.

Organic solvent cleaning was chosen for study because this source category accounts for some 5 percent of stationary source VOC emissions

typical air quality control region. Thus, although individual facilities typically emit less than 100 tons per year, this is a significant source of VOC emissions and the Administrator considers it prudent to continue the development of a standard for this source category.

The metal furniture coating industry is also a significant source of VOC emissions, and there are over 300 existing facilities with the potential to emit more than 100 tons per year.

Lead acid battery manufacture is a significant source of lead emissions. An NSPS for this source category is expected to assist in attainment of the National Ambient Air Quality Standard for lead.

Stationary gas turbines are included on this list because this source category had not been listed by August 7, 1977, when the Clean Air Act Amendments were enacted. However, this source category has not been prioritized, since it was listed under section 111(b)(1)(A) and NSPS were proposed October 3, 1977.

One listed source category which deserves special attention is the synthetic organic chemical manufacturing industry (SOCMI). Preliminary estimates indicate that there may be over 600 different processes included in this source category, but only 27 of these processes have been evaluated. For the others, there was not enough information available. As is the case with several other aggregated source categories, generic standards will be used to cover as many of the sources as possible, so separate NSPS for each of the 600 processes are unlikely.

Based on an effort which has been underway within EPA for two years to study this complex source category, the generic standards could regulate nearly all emissions by covering four broad areas: Process facilities, storage facilities, leakage, and transport and handling losses. Also, since a number of the pollutants emitted are potentially toxic or carcinogenic, regulation under section 112, National Emission Standards for Hazardous Air Pollutants (NESHAP), rather than NSPS may be more appropriated. Therefore, SOCMI is listed as a single source category. The 27 processes considered the most likely candidates for NSPS or NESHAP coverage through generic standards are listed in the preamble to the proposed priority list and discussed in the background documents.

Additional information has resulted in the exclusion from the list of some source categories which are shown in the background reports. Mixed fuel boilers and feed and grain milling are regulated by the NSPS for fossil-fuel steam generators and grain elevators, respectively. Beer manufacture has a much lower emission level than had been assumed in the background report, and whiskey manufacture was deleted due to a lack of any demonstrated control technology.

Public Participation

The Clean Air Act requires that the Administrator, prior to promulgating this list of source categories, consult with Governors and State air pollution control agencies. An invitation was extended on February 28, 1978, to the State and Territorial Air Pollution Program Administrators (STAPPA) and the National Governors' Association (NGA) to attend the first Working Group meeting, March 16, 1978, and review the draft background report and the methods used to apply the priority criteria. On March 24, 1978, each Governor and the director of each State air pollution control agency was notified by letter of this project, including an invitation to participate or comment:

(1) At the April 5–6, 1978, National Air Pollution Control Techniques Advisory Committee (NAPCTAC) meeting in Alexandria, Virginia;

(2) When the final background report was mailed to them;

(3) When the list was proposed in the **Federal Register**; or

(4) At a public hearing to be held on the proposed list. The draft background report for the proposed list was mailed to all NAPCTAC members, five of which represent State or local agencies, two of which represent environmental groups, and eight of which represent industry. Copies were mailed to six environmental groups and three consumer groups at the same time, and to a representative of the NGA. Copies of the final background report for the proposed list were sent to the Governors, State and local air pollution control agencies, NAPCTAC members, environmental groups, the NGA, and other requesters in July 1978.

The public comment period on the proposed list published in the August 31, 1978, **Federal Register**, extended through October 30, 1978. There were 18 comment letters received, 10 from industry and 8 from various regulatory agencies. Several comments resulted in changes to the proposed priority list.

A public hearing was held on September 29, 1978, to discuss the proposed priority list in accordance with section 111(g)(8) of the Clean Air Act. There were no written comments and only one verbal statement resulting from the public hearing.

Significant Comments and Changes to the Proposed Priority List

As a result of public comments and the availability of new screening studies and reports, 34 major and 11 minor source category data sets were reevaluated. This reexamination resulted in data changes for 29 major and 9 minor source categories.

Ten source categories have been removed from the proposed priority list. Eight of these source category deletions are a result of new data indicating that NSPS would have little or no effect. These source categories are: Varnish, carbon black, explosives, acid sulfite wood pulping, NSSC wood pulping, gasoline additives manufacturing, alfalfa dehydrating, and hydrofluoric acid manufacturing. Printing ink manufacturing was reclassified from a major to a minor source category. In addition, two source categories, gray iron and steel foundries, were combined into one source category. Finally, fuel conversion was removed from the list due to uncertainties regarding the approach and scheduled involved in developing environmental standards for the various processes. Likely candidates for NSPS include coal gasification (both low and high pressure), coal liquefaction, and oil shale and tar sand processing. These actions reduce the final priority list to 59 source categories.

The most significant comments and changes made to the proposed regulations are discussed below:

1. *Definition of "Mobility."* Several commenters felt that the treatment of source category mobility (movability) was too broad. Mobility in the prioritization analysis refers to the feasibility a stationary source has to relocate to, or locate new facilities in, areas with less stringent air pollution control regulations. Non-movable stationary source categories were identified on the basis of being firmly tied either to the market (e.g., dry cleaners) or to a supply of materials (e.g., mining operations). The Administrator recognizes that there are many other factors which would be considered in plant siting situations, but considers the approach used in determining the priority list sufficient for the purposes of this study.

2. *Source Category Aggregation.* Several commenters indicated that there were discrepancies between the source categories named in the priority list and those in the background document. The differences between the priority listing in the **Federal Register** and the background document list is a result of aggregation of sources which had been

subcategorized for size classification and priority ranking analysis in the background document. Aggregation indicates that all source categories under a generic industry heading, such as non-metallic mineral processing, will be evaluated at the same time, although this does not necessarily imply that a single standard would apply to all sources within the listed category.

3. *Control Costs.* Two commenters felt that the cost of pollution control to meet NSPS limitations should have been included in the criteria for prioritization. The Clean Air Act priority list criteria do not include the cost of pollution control, but pollution control costs were considered during the determination of control technology assumed for the priority list study. Control costs are examined in more detail during NSPS development studies for each source category, and must be considered in determining each NSPS.

4. *Minor Source Categories.* One commenter felt that the Administrator lacks statutory authority to make a policy decision to develop NSPS for a minor source category until after the major sources have been dealt with, since Congress indicated major sources must be given priority. The Administrator, in promulgating this list, is placing an almost exclusive emphasis on NSPS for major source categories. However, the Clean Air Act does not prohibit concurrent promulgation of NSPS for minor, but significant, source categories. For the three minor source categories listed in this regulation, NSPS development had been initiated before the priority list was available, and completion of standards development for these sources is considered justified.

5. *Stationary Fuel Combustion/Waste Incineration.* Two State agencies felt that stationary fuel combustion and waste incineration should have a high priority because of source activity growth in their respective States. In the promulgated list, both of these source categories are given high priority based on the most recent growth rates available. Given the concern expressed by these agencies, the Administrator has already initiated standard development studies for these source categories.

6. *Chemical Products Manufacture/Fuel Conversion.* One commenter felt that the growth rate and, therefore, the need for coal gasification plant NSPS is overestimated. High Btu coal gasification was reexamined; although no commercial-scale plants currently exist in this country, environmental programs need to keep pace with the emphasis on energy programs. The fuel conversion processes have been removed from the priority list for special study.

7. *Chemical Products Manufacture/Printing Ink Manufacture.* One commenter indicated that neither existing conditions within the printing ink industry nor projections of future growth of the industry justify its categorization as a major source. The Administrator has examined the new data provided, and has reclassified printing ink manufacturing plants as a minor source category. As was discussed earlier, however, the Administrator may still develop standards for "minor" source categories, especially those which, in aggregate, represent a significant quantity of emissions.

8. *Wood Processing/NSSC and Acid Sulfite Pulping.* One commenter indicated that acid sulfite pulp production is a declining growth industry and therefore should not be included in the priority list. The Administrator agrees with this comment, based on examination of acid sulfite pulp production projections in a new screening study. In addition, the screening study indicates that NSSC pulping is, in effect, controlled by the promulgated NSPS for Kraft pulp mills, resulting in little or no further emission reduction from promulgation of an NSSC NSPS. Therefore, both acid sulfite and NSSC pulping have been removed from the list.

Development of Standards

The Administrator has undertaken a program to promulgate NSPS for the source categories on this priority list by August 7, 1982. Development of standards has already been initiated for nearly two-thirds of the source categories listed; work on the remaining source categories will be initiated within the next year.

The priority ranking is indicated by the number to the left of each source category and will be used to decide the order in which new projects are initiated, although this is not necessarily an indication of the order in which projects will be completed. In fact, higher priority source categories often present difficult technical and regulatory problems, and may be among the later source categories for which standards are promulgated.

It should be pointed out that several of the source categories listed could be subject to standards which may be adopted under section 112 of the Clean Air Act, national emission standards for hazardous air pollutants (NESHAP). Included are byproduct coke ovens and several source categories within the petroleum transport and marketing industry. If standards are developed under section 112 for these or any other source categories on the promulgated list, then standards may not be developed for those source categories under section 111.

Promulgation of this list not only fulfills the section 111(f) requirements concerning establishment of priorities, but also constitutes notice that all source categories on the priority list are considered significant sources of air pollution and are hereby listed in accordance with section 111(b)(1)(A). It should be noted, however, that the source categories identified on this priority list, even though listed in accordance with section 111(b)(1)(A), are not subject to the provisions of section 111(b)(1)(B), which would require proposal of an NSPS for each listed source category within 120 days of adoption of the list. Rather, the promulgation of standards for sources contained on this priority list will be undertaken in accordance with the time schedule prescribed in section 111(f)(1) of the Clean Air Act Amendments. That is, NSPS for 25 percent of these source categories are to be promulgated by August 1980, 75 percent by August 1981, and all of the NSPS by August 1982.

Dated August 15, 1979.

Douglas M. Costle,

Administrator.

Part 60 of Chapter I of Title 40 of the Code of Federal Regulations is amended by adding § 60.16 to Subpart A as follows:

§ 60.16 Priority list.

Prioritized Major Source Categories

*Priority Number**

Source Category

1. Synthetic Organic Chemical Manufacturing
   (a) Unit processes
   (b) Storage and handling equipment
   (c) Fugitive emission sources
   (d) Secondary sources
2. Industrial Surface Coating: Cans
3. Petroleum Refineries: Fugitive Sources
4. Industrial Surface Coating: Paper
5. Dry Cleaning
   (a) Perchloroethylene
   (b) Petroleum solvent
6. Graphic Arts
7. Polymers and Resins: Acrylic Resins
8. Mineral Wool
9. Stationary Internal Combustion Engines
10. Industrial Surface Coating: Fabric
11. Fossil-Fuel-Fired Steam Generators
    Industrial Boilers
12. Incineration: Non-Municipal
13. Non-Metallic Mineral Processing
14. Metallic Mineral Processing

* Low numbers have highest priority, e.g., No. 1 is high priority; No. 59 is low priority.

15. Secondary Copper
16. Phosphate Rock Preparation
17. Foundries: Steel and Gray Iron
18. Polymers and Resins: Polyethylene
19. Charcoal Production
20. Synthetic Rubber
    (a) Tire manufacture
    (b) SBR production
21. Vegetable Oil
22. Industrial Surface Coating: Metal Coil
23. Petroleum Transportation and Marketing
24. By-Product Coke Ovens
25. Synthetic Fibers
26. Plywood Manufacture
27. Industrial Surface Coating: Automobiles
28. Industrial Surface Coating: Large Appliances
29. Crude Oil and Natural Gas Production
30. Secondary Aluminum
31. Potash
32. Sintering: Clay and Fly Ash
33. Glass
34. Gypsum
35. Sodium Carbonate
36. Secondary Zinc
37. Polymers and Resins: Phenolic
38. Polymers and Resins: Urea—Melamine
39. Ammonia
40. Polymers and Resins: Polystyrene
41. Polymers and Resins: ABS–SAN Resins
42. Fiberglass
43. Polymers and Resins: Polypropylene
44. Textile Processing
45. Asphalt Roofing Plants
46. Brick and Related Clay Products
47. Ceramic Clay Manufacturing
48. Ammonium Nitrate Fertilizer
49. Castable Refractories
50. Borax and Boric Acid
51. Polymers and Resins Polyester Resins
52. Ammonium Sulfate
53. Starch
54. Perlite
55. Phosphoric Acid: Thermal Process
56. Uranium Refining
57. Animal Feed Defluorination
58. Urea (for fertilizer and polymers)
59. Detergent

Other Source Categories

Lead acid battery manufacture**
Organic solvent cleaning**
Industrial surface coating metal furniture**
Stationary gas turbines***

(Sec. 111, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7601))

[FR Doc. 79-25856 Filed 8-20-79, 8:45 am]

BILLING CODE 6560-01-M

** Minor source category but included on list since an NSPS is being developed for that source category.

*** Not prioritized, since an NSPS for this major source category has already been proposed.

100

40 CFR Part 60

[FRL 1231-3]

Standards of Performance for New Stationary Sources: Asphalt Concrete; Review of Standards

AGENCY: Environmental Protection Agency (EPA)

ACTION: Review of Standards.

SUMMARY: EPA has reviewed the standard of performance for asphalt concrete plants (40 CFR 60.9, Subpart I). The review is required under the Clean Air Act, as amended August 1977. The purpose of this notice is to announce EPA's intent not to undertake revision of the standards at this time.

DATES: Comments must be received by October 29, 1979.

ADDRESS: Comments should be submitted to the Central Docket Section (A-130), U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460, Attention: Docket No. A-79-04.

FOR FURTHER INFORMATION CONTACT: Mr. Robert Ajax, telephone: (919) 541-5271. The document "A Review of Standards of Performance for New Stationary Sources—Asphalt Concrete" (EPA-450/3-79-014) is available upon request from Mr. Robert Ajax (MD-13), Emission Standards and Engineering Division, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

SUPPLEMENTARY INFORMATION:

Background

In June 1973, EPA proposed a standard under Section 111 of the Clean Air Act to control particulate matter emissions from asphalt concrete plants. The standard, promulgated on March 8, 1974, limits the discharge of particulate matter into the atmosphere to a maximum of 90 mg/dscm from any affected facility. The standard also limits the opacity of emissions to 20 percent. The standard is applicable to asphalt concrete plants which commenced construction or modification after June 11, 1973.

The Clean Air Act Amendments of 1977 require that the Administrator of the EPA review and, if appropriate, revise established standards of performance for new stationary sources at least every 4 years [Section 111(b)(1)(B)]. Following adoption of the Amendments, EPA contracted with the MITRE Corporation to undertake a review of the asphalt concrete industry and the current standard. The MITRE review was completed in January 1979. Preliminary findings were presented to and reviewed by the National Air Pollution Control Techniques Advisory Committee at its meeting in Alexandria, Virginia, on January 10, 1979. This notice announces EPA's decision regarding the need for revision of the standard. Comments on the results of this review and on EPA's decision are invited.

Findings

Overview of the Asphalt Concrete Industry

The asphalt concrete industry consists of about 4,500 plants, widely dispersed throughout the Nation. Plants are stationary (60 percent), mobile (20 percent), or transportable (20 percent), i.e., easily taken down, moved and reassembled. Types of plants include batch-mix (91 percent), continuous mix (6.5 percent), or dryer-drum mix (2.5 percent). The dryer-drum plants, which are becoming increasingly popular, differ from the others in that drying of the aggregate and mixing with the liquid asphalt both take place in the same rotary dryer. It is estimated that within the next few years, dryer-drum plants will represent up to 85 percent of all plants under construction.

Current national production is about 263 to 272 million metric tons (MG)/year, with a continued rise expected in the future. It is estimated that approximately 100 new and 50 modified plants become subject to the standard each year. Operation is seasonal, with plants reportedly averaging 666 hours/year although many operate more extensively.

Particulate Matter Emissions and Control Technology

The largest source of particulate emissions is the rotary dryer. Both dry (fabric filters) and wet (scrubbers) collectors are used for control and are both capable of achieving compliance with the standard. However, all systems of these types have not automatically achieved control at or below the level of the standard.

Based on data from a total of 72 compliance tests, it was found that 53 or about three-fourths of the tests for particulate emissions showed compliance. Thirty-three of the 53 produced results between 45 and 90 Mg^3/dscm (.02 and .04 gr/dscf). Of the 47 tests of fabric filters or venturi scrubber controlled sources over 80 percent showed compliance. The available data do not provide details on equipment design and an analysis of the cause of failures has not been performed. However, EPA is not aware of any instances in which a properly designed and installed fabric filter system or high-efficiency scrubber has failed to achieve compliance with the standard. The fact that certian facilities controlled by fabric filters and high-efficiency scrubbers have failed to comply is attributed to faulty design, installation, and/or operation. This conclusion and these data are consistent with data and findings considered in the development of the present standard.

On the basis of these findings, EPA concludes that the present standard for particulate matter is appropriate and that no revision is needed.

Much less test data are available for opacity than for particulates. Of the 26 tests for which opacity levels are reported, only 5 failed to show compliance with the opacity standard. However, none of these 5 met the standard for particulate matter. Of the 21 plants reported as meeting the current standard for opacity, 19 met the particulate standard. On the basis of these data, EPA concludes that the opacity standard is appropriate and should not be revised. While the data do indicate that a tighter standard may be possible, the rationale and basis used to establish the present standard are considered to remain valid.

Enforcement of the Standard

Because the cost of performance tests which are required to demonstrate compliance with the standard are essentially fixed and are independent of plant size, this cost is disproportionately high for small plants. Due to this, the issue was raised as to whether formal testing could be waived and lower cost, alternative means be established for determining compliance at small plants. Support for such a waiver can be found in the fact that emission rates are generally lower at these plants and errors in compliance determinations would not be large in terms of absolute emissions. However, testing costs at all sizes of plants are small in relation to the cost of asphalt concrete production over an extended period and these costs can be viewed as a legitimate expense to be considered by an owner at the time a decision to construct is made. A number of State agencies presently require, under SIP regulations, initial and in some cases annual testing of asphalt concrete plants. Moreover, available compliance test data show that performance of control devices is variable and even with installation of accepted best available control technology the standard can be exceeded by a significant degree if the control system is not properly designed, operated, and maintained. Relaxing the requirement for formal testing thus could lead to a proliferation of low quality or marginal control equipment which would require costly repair or retrofit at a later time.

A further performance testing problem indentified in the review of the standard concerns operation at less than full production capacity during a compliance test. When this occurs, EPA normally accepts the test result as a demonstration of compliance at the tested production rate, plus 23 Mg (25 tons)/hr. To operate at a higher production rate, an owner or operator must demonstrate compliance by testing at that higher rate. Industry representatives view this limitation as an unfair production penalty. It is noted in particular that reduced production is sometimes an unavoidable consequence associated with use of high moisture content aggregate. Furthermore, it is argued that facilities which show compliance at the maximum production rate associated with a given moisture level can be assumed to comply at higher production rates when moisture is lower. However, this argument assumes that the uncontrolled emission rate from the facility does not increase as production rate increases and EPA is not aware of data to support this assumption.

As a general policy it is EPA's intent to minimize administrative costs imposed on owners and operators by a standard, to the maximum extent that this can be done without sacrificing the Agency's responsibility for assuring

compliance. Specifically, in the cases cited above, EPA does not intend to impose costly testing requirements on small facilities or any facilities if compliance with the standard can be determined through less costly means. However, EPA at this time is not aware of a procedure which could be employed at a significantly lower cost to determine compliance with an acceptable degree of accuracy. Although opacity correlaters with grain loading and serves as a valid means for identifying excess emissions, due to dependence on stack diameter and other factors opacity alone is not adequate to accurately assess compliance with the mass rate standard. Similarly, the purchase and installation of a baghouse or venturi scrubber does not in itself necessarily imply compliance. EPA is concerned that approval of such equipment without compliance test data or a detailed assessment of design and operating factors would provide an incentive for installation of low cost, under-designed equipment. This would place vendors of more costly systems which are well designed and properly constructed and operated at a competitive disadvantage; in the long term this would not only increase emissions but would be to the detriment of the industry.

EPA has, however, concluded that a study program to investigate alternative compliance test and administrative approaches for asphalt plants is needed. An EPA contractor working for the Office of Enforcement has initiated a study designed to assess several administrative aspects of the standard, including possible low cost alternative test methods; administrative mechanisms to deal with the problem of process variability during testing; and physical constraints affecting the ability to perform tests. If the results of this program, which is scheduled to be completed later in 1979, show that the regulations or enforcement policies can be revised to lower costs, such revisions will be adopted.

Hydrocarbon Emissions

While the principal pollutant associated with asphalt concrete production is particulate matter, the trend noted previously toward dryer-drum mix plants has raised question as to the significance of hydrocarbon emissions from these facilities. In the dryer-drum mix plant, drying of the aggregate as well as mixing with asphalt and additional fines takes place within a rotary drum. Because the drying takes place within the same container as the mixing, emissions are partly screened by the curtain of asphalt added so that the uncontrolled particulate emissions from the dryer are lower than from conventional plants. In contrast, it has been reported that the rate of hydrocarbon emissions may be substantially higher than from conventional plants. However, data recently reported from one test in a plant equipped with fabric filters showed only traces of hydrocarbons in dust and condensate and did not support this suggestion. Thus, while these data do not indicate a need to revise the standard, more definitive data are needed on hydrocarbon emission rates and related process variables. This has been identified as an area for further research by EPA.

An additional source of hydrocarbon emissions in the asphalt industry is the use of cutback asphalts. Although not directly associated with asphalt concrete plants, this represents a significant source of hydrocarbon emissions. As such, the need for possible standards of performance pertaining to use of cutback asphalt was rasied in this review. The term cutback asphalt refers to liquified asphalt products which are diluted or cutback by kerosene or other petroleum distillates for use as a surfacing material. Cutback asphalt emits significant quantities of hydrocarbons—at a high rate immediately after application and continuing at a diminishing rate over a period of years. It is estimated that over 2 percent of national hydrocarbon emissions result from use of cutback asphalt.

The substitution of emulsified asphalts, which consist of asphalt suspended in water containing an emulsifying agent, for cutback asphalt nearly eliminates the release of volatile hydrocarbons from paving operations. This substitute for petroleum distillate is approximately 98 percent water and 2 percent emulsifiers. The water in emulsified asphalt evaporates during curing while the non-volatile emulsifier is retained in the asphalt.

Because cutback asphalt emissions result from the use of a product rather than from a conventional stationary source, the feasibility of a standard of performance is unclear and the Agency has no current plans to develop such a standard. However, EPA has issued a control techniques guideline document, *Control of Volatile Organic Compounds from Use of Cutback Asphalt* (EPA-450/2-77-037) and is actively pursuing control through the State Implementation Plan process in areas where control is needed to attain oxidant standards. Because of area-to-area differences in experience with emulsified asphalt, availability of suppliers, and ambient temperatures, the Agency believes that control can be implemented effectively by the States.

Asphalt Recycling Plants

A process for recycling asphalt paving by crushing up old road beds for reprocessing through direct-fired asphalt concrete plants has been recently implemented on an experimental basis. Plants using this process, which uses approximately 20 to 30 percent virgin material mixed with the recycled asphalt, are subject to the standard and at least two have demonstrated compliance. However, preliminary indications are that the process may have difficulty in routinely attaining the allowable level of particulate emissions and/or that the cost of control may be higher than a conventional process. The partial combustion of the recycled asphalt cement reportedly produces a blue smoke more difficult to control than the mineral dusts of plants using virgin material.

It is EPA's conclusion that there is no need at this time to revise the standard as it affects recycling, due to its limited practice and due to the data showing that compliance can be achieved at facilities which recycle asphalt. However, this matter is being studies further under the previously noted study by an EPA contractor.

Educational Program for Owners and Operators

The asphalt industry consists of a large number of facilities which in many cases are owned and operated by small businessmen who are not trained or experienced in the operation, design, or maintenance of air pollution control equipment. Because of this, the need to comply with emission regulations, and the changing technology in the industry (i.e., the introduction of dryer-drum plants, recycling, the possible move toward coal as a fuel, and the use of emulsions), the need for a training and educational program for owners and operators in the operation and maintenance of air pollution control equipment has been voiced by industry. This offers the potential for cost and energy savings along with reduced pollution.

To meet this need, EPA's Office of Enforcement, in cooperation with the National Asphalt Paving Association, conducted a series of workshops in 1978 for asphalt plant owners and operators. Only limited future workshops are currently planned. However, EPA will consider expansion of the programs if a continued need exists.

Dated: August 23, 1979.

Douglas Costle,

Administrator

101

40 CFR Part 60

[FRL 1276-2]

Standards of Performance for New Stationary Sources; Gas Turbines

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This rule establishes standards of performance which limit emissions of nitrogen oxides and sulfur dioxide from new, modified and reconstructed stationary gas turbines. The standards implement the Clean Air Act and are based on the Administrator's determination that stationary gas turbines contribute significantly to air pollution. The intended effect of this regulation is to require new, modified and reconstructed stationary gas turbines to use the best demonstrated system of continuous emission reduction.

EFFECTIVE DATE: September 10, 1979.

ADDRESSES: The Standards Support and Environmental Impact Statement (SSEIS) may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711 (specify *Standards Support and Environmental Impact Statement, Volume 2: Promulgated Standards of Performance for Stationary Gas Turbines*, EPA-450/2-77-017b).

FOR FURTHER INFORMATION CONTACT: Don R. Goodwin, Director, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone No. (919) 541-5271.

SUPPLEMENTARY INFORMATION:

The Standards

The promulgated standards apply to all new, modified, and reconstructed stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (about 1,000 horsepower). The standards apply to simple and regenerative cycle gas turbines and to the gas turbine portion of a combined cycle steam/electric generating system.

The promulgated standards limit the concentration of nitrogen oxides (NO_x) in the exhaust gases from stationary gas turbines with a heat input from 10.7 to and including 107.2 gigajoules per hour (about 1,000 to 10,000 horsepower), from offshore platform gas turbines, and from stationary gas turbines used for oil or gas transportation and production not located in a Metropolitan Statistical Area (MSA), to 0.0150 percent by volume (150 PPM) at 15 percent oxygen on a dry basis. The promulgated standards also limit the concentration of NO_x in the exhaust gases from stationary gas turbines with a heat input greater than 107.2 gigajoules per hour, and from stationary gas turbines used for oil or gas transportation and production located in an MSA, to 0.0075 percent by volume (75 PPM) at 15 percent oxygen on a dry basis (see Table 1 for summary of NO_x emission limits). Both of these emission limits (75 and 150 PPM) are adjusted upward for gas turbines with thermal efficiencies greater than 25 percent using an equation included in the promulgated standards. These emission limits are also adjusted upward for gas turbines burning fuels with a nitrogen content greater than 0.015 percent by weight using a fuel-bound nitrogen allowance factor included in the promulgated standards, or a "custom" fuel-bound nitrogen allowance factor developed by the gas turbine manufacturer and approved for use by EPA. Custom fuel-bound nitrogen allowance factors must be substantiated with data and approved for use by the Administrator before they may be used for determining compliance with the standards.

The promulgated NO_x emission limits are referenced to International Standard Organization (ISO) standard day conditions of 288 degrees Kelvin, 60 percent relative humidity, and 101.3 kilopascals (1 atmosphere) pressure. Measured NO_x emission levels, therefore, are adjusted to ISO reference conditions by use of an ambient condition correction factor included in the standards, or by a custom ambient condition correction factor developed by the gas turbine manufacturer and approved for use by EPA. Custom ambient condition correction factors can only include the following variables: combustor inlet pressure, ambient air pressure, ambient air humidity, and ambient air temperature. These factors must be substantiated with data and approved for use by the Administrator before they may be used for determining compliance with the standards.

Stationary gas turbines with a heat input at peak load from 10.7 to, and including, 107.2 gigajoules per hour are to be exempt from the NO_x emission limit included in the promulgated standards for five years from the date of proposal of the standards (October 3, 1977). New gas turbines with this heat input at peak load which are constructed, or existing gas turbines with this heat input at peak load which are modified or reconstructed during this five-year period do not have to comply with the NO_x emission limit included in the promulgated standards at the end of this period. Only those new gas turbines which are constructed, or existing gas turbines which are modified or reconstructed, following this five-year period must comply with the NO_x emission limit.

Emergency-standby gas turbines, military training gas turbines, gas turbines involved in certain research and development activities, and firefighting gas turbines are exempt from compliance with the NO_x emission limits included in the promulgated standards. In addition, stationary gas turbines using wet controls are temporarily exempt from the NO_x emission limit during those periods when ice fog created by the gas turbine is deemed by the owner or operator to present a traffic hazard, and during periods of drought when water is not available.

None of the exemptions mentioned above apply to the sulfur dioxide (SO_2) emission limit. The promulgated standards limit the SO_2 concentration in the exhaust gases from stationary gas turbines with a heat input at peak load of 10.7 gigajoules per hour or more to 0.015 percent by volume (150 PPM) corrected to 15 percent oxygen on a dry basis. The standards include an alternative SO_2 emission limit on the sulfur content of the fuel of 0.8 percent sulfur by weight (see Table 1 for summary of exemptions and SO_2 emission limits).

Table 1.—*Summary of Gas Turbine New Source Performance Standard*

Gas turbine size and usage	NO_x emission limit [1]	Applicability date for NO_x	SO_2 emission limit	Applicability date for SO_2
Less than 10 7 gigajoules/hour (all uses)	None	Standard does not apply	None	Standard does not apply
Between 10 7 and 107 2 gigajoules/hour (all uses)	150 ppm	October 3, 1982	150 ppm SO_2 or fire a fuel with less than 0.8% sulfur	October 3 1977
Greater than or equal to 107 2 gigajoules/hour				
1 Gas and oil transportation or production not located in an MSA	150 ppm	October 3, 1977	Same as above	October 3 1977
2 Gas and oil transportation or production located in an MSA	75 ppm	October 3, 1977	Same as above	October 3, 1977
3. All other uses	75 ppm	October 3, 1977	Same as above	October 3, 1977
Emergency standby, firefighting, military (except for garrison facility), military training, and research and development turbines	None	Standard does not apply	Same as above	October 3 1977

[1] NO_x emission limit adjusted upward for gas turbines with thermal efficiences greater than 25 percent and for gas turbines firing fuels with a nitrogen content of more than 0.015 weight percent. Measured NO_x emissions adjusted to ISO conditions in determining compliance with the NO_x emission limit.

Environmental, Energy, and Economic Impact

The promulgated standards will reduce NO_x emissions by about 190,000 tons per year by 1982 and by 400,000 tons per year by 1987. This reduction will be realized with negligible adverse solid waste and noise impacts.

The adverse water pollution impact associated with the promulgated standards will be minimal. The quantity of water or steam required for injection into the gas turbine to reduce NO_x emissions is less than 5 percent of the water consumed by a comparable size steam/electric power plant using cooling towers. There will be no adverse water pollution impact associated with those gas turbines which employ dry NO_x control technology.

The energy impact associated with the promulgated standards will be small. Gas turbine fuel consumption could increase by as much as 5 percent in the worst cases. The actual energy impact depends on the rate of water injection necessary to comply with the promulgated standards. Assuming the "worst case," however, the standards would increase fuel consumption of large stationary gas turbines (i.e., greater than 10,000 horsepower) by about 5,500 barrels of fuel oil per day in 1982. The standards would increase fuel consumption of small stationary gas turbines (i.e., less than 10,000 horsepower) by about 7,000 barrels of fuel oil per day in 1987. This is equivalent to an increase in projected 1982 and 1987 national crude oil consumption of less than 0.03 percent. As mentioned, these estimates are based on "worst case" assumptions. The actual energy impact of the promulgated standard is expected to be much lower than these estimates because most gas turbines will not experience anywhere near a 5 percent fuel penalty due to water or steam injection. In addition, many gas turbines will comply with the standards using dry control, which in most cases has no energy penalty.

The economic impact associated with the promulgated standards is considered reasonable. The standards will increase the capital costs or purchase price of a gas turbine for most installations by about 1 to 4 percent. The annualized costs will be increased by about 1 to 4 percent, with the largest application, utilities, realizing less than a 2 percent increase.

The promulgated standards will increase the total capital investment requirements for users of large stationary gas turbines by about 36 million dollars by 1982. For the period 1982 through 1987, the standards will increase the capital investment requirements for users of both large and small stationary gas turbines by about 67 million dollars. Total annualized costs for these users of stationary gas turbines will be increased by about 11 million dollars in 1982 and by about 30 million dollars in 1987. These impacts will result in price increases for the end products or services provided by industrial and commercial users of stationary gas turbines ranging from less than 0.01 percent in the petroleum refining industry, to about 0.1 percent in the electric utility industry.

Public Participation

Prior to proposal of the standards, interested parties were advised by public notice in the **Federal Register** of meetings of the National Air Pollution Control Techniques Advisory Committee to discuss the standards recommended for proposal. These meetings occurred on February 21, 1973; May 30, 1973; and January 9, 1974. The meetings were open to the public and each attendee was given ample opportunity to comment on the standards recommended for proposal. The standards were proposed and published in the **Federal Register** on October 3, 1977. Public comments were solicited at that time and, when requested, copies of the Standards Support and Environmental Impact Statement (SSEIS) were distributed to interested parties. The public comment period extended from October 3, 1977, to January 31, 1978.

Seventy-eight comment letters were received on the proposed standards of performance. These comments have been carefully considered and, where determined to be appropriate by the Administrator, changes have been made in the standards which were proposed.

Significant Comments and Changes to the Proposed Regulation

Comments on the proposed standards were received from electric utilities, oil and gas producers, gas turbine manufacturers, State air pollution control agencies, trade and professional associations, and several Federal agencies. Detailed discussion of these comments can be found in Volume 2 of the SSEIS. The major comments can be combined into the following areas: general, emission control technology, modification and reconstruction, economic impacts, environmental impacts, energy impacts, and test methods and monitoring.

General

Small stationary gas turbines (i.e, those with a heat input at peak load between 10.7 and 107.2 gigajoules per hour—about 1,000 to 10,000 horsepower) are exempt from the standards for a period of five years following the date of proposal. Some commenters felt it was not clear whether small gas turbines would be required to retrofit NO_x emissions controls after the exemption period ended. These commenters felt this was not the intent of the standards and they recommended that this point be clarified.

The intent of both the proposed and the promulgated standards is to consider small gas turbines which have commenced construction on or before the end of the five year exemption period as existing facilities. These facilities will not have to retrofit at the end of the exemption period. This point has been clarified in the promulgated standards.

Several commenters requested exemptions for temporary and intermittent operation of gas turbines to permit research and development into advanced combustion techniques under full scale conditions.

This is considered a reasonable request. Therefore, gas turbines involved in research and development for the purpose of improving combustion efficiency or developing emission control technology are exempt from the NO_x emission limit in the promulgated standards. Gas turbines involved in this type of research and development generally operate intermittently and on a temporary basis. The standards have been changed, therefore, to allow exemptions in such situations on a case-by-case basis.

Emissions Control Technology

The selection of wet controls, or water injection, as the best system of emission reduction for stationary gas turbines was criticized by a number of commenters. These commenters pointed out that although dry controls will not reduce emissions as much as wet controls, dry controls will reduce NO_x emissions without the objectionable results of water injection (i.e., increased fuel consumption and difficulty in securing water of acceptable quality). These commenters, therefore, recommended postponement of standards until dry controls can be implemented on gas turbines.

As pointed out in Volume 1 of the SSEIS, a high priority has been established for control of NO_x emissions. Wet and dry controls are considered the only viable alternative control techniques for reducing NO_x emissions from gas turbines. Control of NO_x emissions by either of these two

alternatives clearly favored the development of the standards of performance based on wet controls from an environmental viewpoint. Reductions in NO_x emissions of more than 70 percent have been demonstrated using wet controls on many large gas turbines used in utility and industrial applications. Thus, wet controls can be applied immediately to large gas turbines, which account for 85–90 percent of NO_x emissions from gas turbines.

The technology of wet control is the same for both large and small gas turbines. The manufacturers of small gas turbines, however, have not experimented with or developed this technology to the same extent as the manufacturers of large gas turbines. In addition, small gas turbines tend to be produced or more of an assembly line basis than large gas turbines. Consequently, the manufacturers of small gas turbines need a lead time of five years (based on their estimates) to design, test, and incorporate wet controls on small gas turbines.

Even with a five-year delay in application of standards to small gas turbines, standards of performance based on wet controls will reduce national NO_x emissions by about 190,000 tons per year by 1982. Therefore, the reduction in NO_x emissions resulting from standards based on wet controls is significant.

Dry controls have demonstrated NO_x emissions reduction of only about 40 percent in laboratory and combustor rig tests. Because of the advanced state of research and development into dry control by the manufacturers of large gas turbines, the much longer lead time involved in ordering large gas turbines, and the greater attention that can be given to "custom" engineering designs of large gas turbines, dry controls can be implemented on large gas turbines immediately. Manufacturers of small gas turbines, however, estimate that it would take them as long to incorporate dry controls as wet controls on small gas turbines. Basing the standards only on dry controls, therefore, would significantly reduce the amount of NO_x emission reductions achieved.

The economic impact of standards based on wet controls is considered reasonable for large gas turbines. (See Economic Impact Discussion.) Thus, wet controls represent ". . . the best system of continuous emission reduction . . . (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) . . ." for large gas turbines.

The economic impact of standards based on wet controls, however, is considered unreasonable for small gas turbines, gas turbines located on offshore platforms, and gas turbines employed in oil or gas production and transportation which are not located in a Metropolitan Statistical Area. The economic impact of standards based on dry controls, on the other hand, is considered reasonable for these gas turbines. (See Economic Impact Discussion.) Thus, dry controls represent ". . . the best system of continuous emission reduction . . . (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) . . ." for small gas turbines, gas turbines located on offshore platforms, and gas turbines employed in oil or gas production and transportation which are not located in a Metropolitan Statistical Area.

Volume 1 of the SSEIS summarizes the data and information available from the literature and other nonconfidential sources concerning the effectiveness of dry controls in reducing NO_x emissions from stationary gas turbines. More recently, additional data and information have been published in the Proceedings of the Third Stationary Source Combustion Symposium (EPA–600/7–79–050C). Advanced Combustion Systems for Stationary Gas Turbines (interim report) prepared by the Pratt and Whitney Aircraft Group for EPA (Contract 68–02–2136), "Experimental Clean Combustor Program Phase III" (NASA CR–135253) also prepared by the Pratt and Whitney Aircraft Group for the National Aeronautics and Space Administration (NASA), and "Aircraft Engine Emissions" (NASA Conference Publication 2021). These data and information show that dry controls can reduce NO_x emissions by about 40 percent. Multiplying this reduction by a typical NO_x emission level from an uncontrolled gas turbine of about 250 ppm leads to an emission limit for dry controls of 150 ppm. This, therefore, is the numerical emission limit included in the promulgated standards for small gas turbines, gas turbines located on offshore platforms, and gas turbines employed in oil or gas production or transportation which are not located in Metropolitan Statistical Areas.

The five-year delay from the date of proposal of the standards in the applicability date of compliance with the NO_x emission limit for small gas turbines has been retained in the promulgated standards. As discussed above, manufacturers of small gas turbines have estimated that it will take this long to incorporate either wet or dry controls on these gas turbines.

Several commenters criticized the fuel-bound nitrogen allowance included in the proposed standards. It was felt that greater flexibility in the equations used to calculate the fuel-bound nitrogen NO_x emissions contribution should be permitted, due to the limited data on conversion of fuel-bound nitrogen to NO_x. These commenters recommended that manufacturers of gas turbines be allowed to develop their own fuel-bound nitrogen allowance.

As discussed in Volume I of the SSEIS, the reaction mechanism by which fuel-bound nitrogen contributes to NO_x emissions is not fully understood. In addition, emission data are limited with respect to fuels containing significant amounts of fuel-bound nitrogen. The problem of quantifying the fuel-bound nitrogen contribution to total NO_x emissions is further complicated by the fact that the amount of nitrogen in the fuel has an effect on this contribution.

In light of this sparsity of data, the commenters' recommendations seem reasonable. Therefore, a provision has been added to the standards to allow manufacturers to develop custom fuel-bound nitrogen allowances for each gas turbine model. The use of these factors, however, must be approved by the Administrator before the initial performance test required by Section 60.8 of the General Provisions. Petitions by manufacturers for approval of the use of custom fuel-bound nitrogen allowance factors must be supported by data which clearly provide a basis for determining the contribution of fuel-bound nitrogen to total NO_x emissions. In addition, in no case will EPA approve a custom fuel-bound nitrogen allowance factor which would permit an increase in NO_x emissions of more than 50 ppm. (See Energy Impact Discussion.) Notice of approval of the use of these factors for various gas turbine models will be given in the **Federal Register.**

Modification and Reconstruction

Some commenters felt that existing gas turbines which now burn natural gas and are subsequently altered to burn oil should be exempt from consideration as modifications. The high cost and technical difficulties of compliance with the standards would discourage fuel switching to conserve natural gas supplies.

As outlined in the General Provisions of 40 CFR Part 60, which are applicable to all standards of performance, most changes to an existing facility which result in an increase in emission rate to

the atmosphere are considered modifications. However, according to section 60.14(e)(4) of the General Provisions, the use of an alternative fuel or raw material shall not be considered a modification if the existing facility was designed to accommodate that alternative use. Therefore, if a gas turbine is designed to fire both natural gas and oil, then switching from one fuel to the other would not be considered a modification even if emissions were increased. If a gas turbine that is not designed for firing both fuels is switched from firing natural gas to firing oil, installation of new injection nozzles which increase mixing to reduce NO_x production, or installation of new NO_x combustors currently on the market, would in most cases maintain emissions at their previous levels. Since emissions would not increase, the gas turbine would not be considered modified, and the real impact of the standards on gas turbines switching from natural gas to oil will probably be quite small. Therefore, no special provisions for fuel switching have been included in the promulgated standards.

Economic Impact

Several commenters stated that water injection could increase maintenance costs significantly. One reason cited was that chemicals and minerals in the water would likely be deposited on internal surfaces of gas turbines, such as turbine blades, leading to downtime for repair and cleaning. In addition, the commenters felt that higher maintenance requirements could be expected due to the increased complexity of a gas turbine with water injection.

As pointed out in Volume 1 of the SSEIS, to avoid deposition of chemicals and minerals on gas turbine blades, the water used for water injection must be treated. Costs for water treatment were included in the overall costs of water injection and, for large gas turbines, these costs are considered reasonable.

Actual maintenance and operating costs for gas turbines operating with water or steam injection are limited. Several major utilities, however, have accumulated significant amounts of operating time on gas turbines using water or steam injection for control of NO_x emissions. There have been some problems attributable to water or steam injection, but based on the data available, these problems have been confined to initial periods of operation of these systems. Most of these reported problems such as turbine blade damage, flame-outs, water hammer damage, and ignition problems, were easily corrected by minor redesign of the equipment hardware. Because of the knowledge gained from these systems, such problems should not arise in the future.

As mentioned, some utilities have accumulated substantial operating experience without any significant increase in maintenance or operating costs or other adverse effects. One utility, for example, has used water injection on two gas turbines for over 55,000 hours without making any major changes to their normal maintenance and operating procedures. They followed procedures essentially identical to those required for a similar gas turbine not using water injection, and the plant experienced no outages attributable to the water injection system. Another company has accumulated over 92,000 hours of operating time with water injection on 17 gas turbines with approximately 116 hours of outage attributable to their water injection system. Increased maintenance costs which can be attributed to these water injection systems are not available, as such costs were not accounted for separately from normal maintenance. However, they were not reported as significant.

Some commenters exresssed the opinion that the cost estimates for controlling NO_x emissions from large gas turbines were too low. Accordingly, these commenters felt that wet control technology should not be the basis of the standards for large stationary gas turbines.

The costs associated with wet control technology for large gas turbines were reassessed. In a few cases, it appeared the water-to-fuel ratio used in Volume 1 of the SSEIS was somewhat low. In these cases, the capital and annualized operating costs associated with wet control on large gas turbines were revised to reflect injection of more water into the gas turbine. None of these revisions, however, resulted in a significant change in the projected economic impact of wet controls on large gas turbines. Thus, depending on the size and end use of large gas turbines, wet controls are still projected to increase capital and annualized operating costs by no more than 1 to 4 percent. Increases of this order of magnitude are considered reasonable in light of the 70 percent reduction in NO_x emissions achieved by wet controls. Consequently, the basis of the promulgated standards for large gas turbines remains the same as that for the proposed standards—wet controls.

A number of commenters also expressed the opinion that the cost estimates for wet controls to reduce NO_x emissions from small gas turbines were too low. Therefore, the standards for small gas turbines should not be based on wet controls.

Information included in the comments submitted by manufacturers of small gas turbines indicated the costs of redesigning these gas turbines for water injection are much greater than those included in Volume 1 of the SSEIS. Consequently, it appears the costs of water injection would increase the capital cost of small gas turbines by about 16 percent, rather than about 4 percent as originally estimated. Despite this increase in capital costs, it does not appear water injection would increase the annualized operating costs of small gas turbines by more than 1 to 4 percent as originally estimated, due to the predominance of fuel costs in operating costs. An increase of 16 percent in the capital cost of small gas turbines, however, is considered unreasonable.

Very little information was presented in Volume 1 of the SSEIS concerning the costs of dry controls. The conclusion was drawn, however, that these costs would undoubtedly be less than those associated with wet controls.

Little information was also included in the comments submitted by the manufacturers of small gas turbines concerning the costs of dry controls. Most of the cost information dealt with the costs of wet controls. One manufacturer, however, did submit limited information which appears to indicate that the capital cost impact of dry controls on small gas turbines might be only a quarter of that of wet controls. Thus, dry controls might increase the capital costs of small gas turbines by only about 4 percent. The potential impact of dry controls on annualized operating costs would certainly be no greater than wet controls, and would probably be much less. Consequently, it appears dry controls might increase the capital costs of small gas turbines by about 4 percent and the annualized operating costs by about 1 to 4 percent.

The magnitude of these impacts is essentially the same as those originally associated with wet controls in Volume 1 of the SSEIS, and they are considered reasonable. Consequently, the basis of the promulgated standards for small gas turbines is dry controls.

A number of commenters stated that the costs associated with wet controls on gas turbines located on offshore platforms, and in arid and remote regions were unreasonable. These commenters felt that the costs of obtaining, transporting, and treating water in these areas prohibited the use of water injection.

As mentioned by the commenters, the costs associated with water injection on gas turbines in these locations are all related to lack of water of acceptable quality or quantity. Review of the costs included in Volume 1 of the SSEIS for water injection on gas turbines located on offshore platforms, indicates that the required expenditures for platform space were not incorporated into these estimates. Based on information included in the comments, platform space is very expensive, and averages approximately $400 per square foot. When this cost is included, the use water treatment systems to provide water for NO_x emissions control would increase the capital costs of a gas turbine located on an offshore platform by approximately 33 percent. This is considered an unreasonable economic impact.

Dry controls, unlike wet controls, would not require additional space on offshore platforms. Although most gas turbines located on offshore platforms would be considered small gas turbines under the standards, it is possible that some large gas turbines might be located on offshore platforms. Therefore, all the information available concerning the costs associated with standards based on dry controls for large gas turbines was reviewed.

Unfortunately, no additional information on the costs of dry controls was included in the comments submitted by the manufacturers of large gas turbines. As mentioned above, the information presented in Volume 1 of the SSEIS is very limited concerning the costs of dry controls, although the conclusion is drawn that these costs would undoubtedly be less than the costs of wet controls. It also seems reasonable to assume that the costs of dry controls on large gas turbines would certainly be less than the costs of dry controls on small gas turbines. Consequently, standards based on dry controls should not increase the capital and annualized operating costs of large gas turbines by more than the 1 to 4 percent projected for small gas turbines. This conclusion even seems conservative in light of the projected increase in capital and annualized operating costs for wet controls on large gas turbines of no more than 1 to 4 percent. In any event, the costs of standards based on dry controls for large gas turbines are considered reasonable. Therefore, the promulgated standards for gas turbines located on offshore platforms are based on dry controls.

In many arid and remote regions, gas turbines would have to obtain water by trucking, installing pipelines to the site, or by construction of large water reservoirs. While costs included in Volume 1 of the SSEIS do not show trucking of water to gas turbine sites to be unreasonable, these costs are not based on actual remote area conditions. That is, these costs are based on paved road conditions and standard ICC freight rates. Gas turbines located in arid and remote regions, however, are not likely to have good access roads. Consequently, it is felt that the costs of trucking water, laying a water pipeline, or constructing a water reservoir would be unreasonable for most arid and remote areas.

As discussed above, the economic impact of standards based on dry controls for both large and small gas turbines in considered reasonable. Consequently, provisions have been included in the promulgated standards which essentially require gas turbines located in arid and remote areas to comply with an NO_x emission limit based on the use of dry controls. A number of options were considered before the specific provisions included in the promulgated standards were selected.

The first option considered was defining the term "arid and remote." While this is conceptually straightforward, it proved impossible to develop a satisfactory definition for regulatory purposes. The second option considered was defining all gas turbines located more than a certain distance from an adequate water supply as "arid and remote" gas turbines. Defining the distance and an adequate water supply, however, proved as impossible as defining the term "arid and remote." The third option considered was a case-by-case exemption for gas turbines where the costs of wet controls exceeded certain levels. This option, however, would provide incentive to owners and operators to develop grossly inflated costs to justify exemption and would require detailed analysis of each case on the part of the Agency to insure this did not occur. In addition, the numerous disputes and disagreements which would undoubtedly arise under this option would lead to delays and demands on limited resources within both the Agency and industry to resolve.

Analysis of the end use of most gas turbines located in arid and remote regions gave rise to a fourth option. Generally, gas turbines located in arid or remote regions are used for either oil and gas production, or oil and gas transportation. Consequently, the promulgated standards require gas turbines employed in oil and gas production or oil and gas transportation, which are not located in a Metropolitan Statistical Area (MSA), to meet an NO_x emission limit based on the use of dry controls. The promulgated standards, however, require gas turbines employed in oil and gas production or oil and gas transportation which are located in a MSA to meet the 75 ppm NO_x emission limit. This emission limit is based on the use of wet controls and in an MSA a suitable water supply for water injection will be available.

Environmental Impact

A number of commenters felt gas turbines used as "peaking" units should be exempt. Peaking units operate relatively few hours per year. According to commenters, use of water injection would result in a very small reduction in annual NO_x emissions and negligible improvement in ground level concentrations.

As pointed out in Volume 1 of the SSEIS, about 90 percent of all new gas turbine capacity is expected to be installed by electric utility companies to generate electricity, and possibly as much as 75 percent of all NO_x emissions from stationary gas turbines are emitted from these installations. Of these electric utility gas turbines, a large majority are used to generate power during periods of peak demand. Consequently, by their very nature, peaking gas turbines tend to operate when the need for emission control is greatest, that is, when power demand is highest and air quality is usually at its worst. Therefore, it does not seem reasonable to exempt peaking gas turbines from compliance with the standards.

A number of commenters also felt that small gas turbines should be exempt from the standards because they emit only about 10 percent of the total NO_x emissions from all stationary gas turbines and therefore, the environmental impact of not regulating these turbines would be small.

A high priority has been established for NO_x emission control and dry control

techniques are considered a demonstrated and economically reasonably means for reducing NO_x emissions from small gas turbines. Therefore, the promulgated standards limit NO_x emissions from small gas turbines to 150 ppm based on the use of dry control technology.

Energy Impact

A number of writers commented on the potential impact of the standards on the use of the oil-shale, coal-derived, and other synthetic fuels. It was generally felt that these types of fuels should not be covered by the the standards at this time, since this could hinder their development.

Total NO_x emissions from any combustion source, including stationary gas turbines, are comprised of thermal NO_x and organic NO_x. Thermal NO_x is formed in a well-defined high temperature reaction between oxygen and nitrogen in the combustion air. Organic NO_x is produced by the combination of fuel-bound nitrogen with oxygen during combustion in a reaction that is not yet fully understood. Shale oil, coal-derived, and other synthetic fuels generally have high nitrogen contents and, therefore, will produce relatively high organic NO_x emissions when combusted.

Neither wet nor dry control technology for gas turbines is effective in reducing organic NO_x emissions. As discussed in Volume I of the SSEIS, as fuel-bound nitrogen increases, organic NO_x emissions from a gas turbine become the predominant fraction of total NO_x emissions. Consequently, emission standards must address in some manner the contribution to NO_x emissions of fuel-bound nitrogen.

Low nitrogen fuels, such as premium distillate fuel oil and natural gas, are now being fired in nearly all stationary gas turbines. Energy supply considerations, however, may cause more gas turbines to fire heavy fuel oils and synthetic fuels in the future. A standard based on present practice of firing low nitrogen fuels, therefore, would too rigidly restrict the use of high nitrogen fuel, especially in light of the uncertainty in world energy markets.

Since control technology is not in reducing organic NO_x emissions from gas turbines, the possibility of basing standards on removal of nitrogen from the fuel prior to combustion was considered. The cost of removing nitrogen from fuel oil, however, ranges from $2.00 to $3.00 per barrel. Another alternative considered was exempting gas turbines using high nitrogen fuels, as some commenters requested. Exempting gas turbines based on the type of fuel used, however, would not require the use of best control technology in all cases.

A third alternative considered was the use of a fuel-bound nitrogen allowance. Beyond some point it is simply not reasonable to allow combustion of high nitrogen fuels in gas turbines. In addition, high nitrogen fuels, including shale oil and coal-derived fuels, can be used in other combustion devices where some control of organic NO_x emissions is possible. Greater reduction of nationwide NO_x emissions could be achieved by utilizing these fuels in facilities where organic NO_x emission control is possible than in gas turbines where organic NO_x emissions are essentially uncontrolled. This approach, therefore, balances the trade-off between allowing unlimited selection of fuels for gas turbines controlling NO_x emissions.

A limited fuel-bound nitrogen allowance which would allow increased NO_x emissions above the numerical NO_x emissions limits including in the promulgated standards seems most reasonable. An upper limit on this allowance of 50 ppm NO_x was selected. Such a limit would allow approximately 50 percent of existing heavy fuel oils to be fired in stationary gas turbines. (See Volume I of the SSEIS.) This approach is considered a reasonable means of allowing flexibility in the selection of fuels while achieving reductions in NO_x emissions from stationary gas turbines. (See Control Technology for further discussion.)

A number of commenters felt the efficiency correction factor included in the standards should use the overall efficiency of a gas turbine installation rather than the thermal efficiency of the gas turbine itself. For example, many commenters recommended that the overall efficiency of a combined cycle gas turbine installation be used in this correction factor.

Section 111 of the Clean air Act requires that standards of performance for new sources reflect the use of the best system of emission reduction. With the few exceptions noted above, water injection is considered the best system of emission control for reducing NO_x emissions from stationary gas turbines. To be consistent with the intent of section 111, the standards must reflect the use of water injection independent of any ancillary waste heat recovery equipment which might be associated with a gas turbine to increase its overall efficiency. To allow an upward adjustment in the NO_x emission limit based on the overall efficiency of a combined cycle gas turbine could mean that water injection might not have to be applied to the gas turbine. Thus, the standards would not reflect the use of the best system of emission reduction. Therefore, the efficiency factor must be based on the gas turbine efficiency itself, not the overall efficiency of a gas turbine combined with other equipment.

Test Methods and Monitoring

A large number of commenters objected to the amount of monitoring required. The proposed standards called for daily monitoring of sulfur content, nitrogen content, and lower heating value of the fuel. The commenters were generally in favor of less frequent periodic monitoring.

These comments seem reasonable. Therefore, the standards have been changed to permit determination of sulfur content, nitrogen content, and lower heating value only when a fresh supply of fuel is added to the fuel storage facilities for a gas turbine. Where gas turbines are fueled without intermediate storage, such as along oil and gas transport pipelines, daily monitoring is still required by the standards unless the owner or operator can show that the composition of the fuel does not fluctuate significantly. In these cases, the owner or operator may develop an individual monitoring schedule for determining fuel sulfur content, nitrogen content, and lower heating value. These schedules must be substantiated by data and submitted to the Administrator for approval on a case-by-case basis.

Several commenters stated that the standards should be clarified to allow the performance test to be performed by the gas turbine manufacturer in lieu of the owner/operator. To simplify verification of compliance with the standards and to reduce costs to everyone involved, the recommendation was made that each gas turbine be performance tested at the manufacturer's site. The commenters maintained that gas turbines should not be required to undergo a performance test at the owner/operator's site if they have been shown to comply with the standard by the gas turbine manufacturer.

Section 111 of the Clean Air Act is not flexible enough to permit the use of a formal certification program such as that described by the commenter. Responsibility for complying with the standards ultimately rests with the owner/operator, not with the gas turbine manufacturers. The general provisions of 40 CFR Part 60, however, which apply to all standards of performance, allow the use of approaches other than performance tests to determine compliance on a case-by-case basis. The

alternate approach must demonstrate to the Administrator's satisfaction that the facility is in compliance with the standard. Consequently, gas turbine manufacturers' tests may be considered, on a case-by-case basis, in lieu of performance tests at the owner/operator's site to demonstrate compliance with the standards. For a gas turbine manufacturers's test to be acceptable in lieu of a performance test, as a minimum the operating conditions of the gas turbine at the installation site would have to be shown to be similar to those during the manufacturer's test. In addition, this would not preclude the Administrator from requiring a performance test at any time to demonstrate compliance with the standards.

Miscellaneous

It should be noted that standards of performance for new stationary sources established under section 111 of the Clean Air Act reflect:

". . . application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environment impact and energy requirements) the Administrator determines has been adequately demonstrated. [section 111(a)(1)]

Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act requires (or has potential for requiring) the imposition of a more stringent emission standard in several situations.

For example, applicable costs do not play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources located in nonattainment areas, i.e., those areas where statutorily mandated health and welfare standards are being violated. In this respect, section 173 of the act requires that a new or modified source constructed in an area which exceeds the National Ambient Air Quality Standard (NAAQS) must reduce emissions to the level which reflects the "lowest achievable emission rate" (LAER), as defined in section 171(3), for such category of source. The statute defines LAER as that rate of emission which reflects:

(A) The most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or

(B) The most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent.

In no event can the emission rate exceed any applicable new source performance standard (section 171(3)).

A similar situation may arise under the prevention of significant deterioration of air quality provisions of the Act (part C). These provisions require that certain sources (referred to in section 169(1)) employ "best available control technology" (as defined in section 169(3)) for all pollutants regulated under the Act. Best available control technology (BACT) must be determined on a case-by-case basis, taking energy, environmental and economic impacts, and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the Act.

In all events, State implementation plans (SIPs) approved or promulgated under section 110 of the Act must provide for the attainment and maintenance of National Ambient Air Quality Standards designed to protect public health and welfare. For this purpose, SIPs must in some cases require greater emission reductions than those required by standards of performance for new sources.

Finally, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

This regulation will be reviewed 4 years from the date of promulgation. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, and improvements in emissions control technology.

No economic impact assessment under Section 317 was prepared on this standard. Section 317(a) requires such an assessment only if "the notice of proposed rulemaking in connection with such standard . . . is published in the **Federal Register** after the date ninety days after August 7, 1977." This standard was proposed in the **Federal Register** on October 3, 1977, less than ninety days after August 7, 1977, and an assessment was therefore not required.

Dated: August 28, 1979.

Douglas M. Costle,

Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

It is proposed to amend Part 60 of Chapter I, Title 40 of the Code of Federal Regulations as follows:

1. By adding subpart GG as follows:

Subpart GG—Standards of Performance for Stationary Gas Turbines

Sec.

60.330 Applicability and designation of affected facility.
60.331 Definitions.
60.332 Standard for nitrogen oxides.
60.333 Standard for sulfur dioxide.
60.334 Monitoring of operations.
60.335 Test methods and procedures.

Authority: Secs. 111 and 301(a) of the Clean Air Act, as amended, [42 U.S.C. 1857c-7, 1857g(a)], and additional authority as noted below.

Subpart GG—Standards of Performance for Stationary Gas Turbines

§ 60.330 Applicability and designation of affected facility.

The provisions of this subpart are applicable to the following affected facilities: all stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour, based on the lower heating value of the fuel fired.

§ 60.331 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) "Stationary gas turbine" means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) "Simple cycle gas turbine" means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) "Regenerative cycle gas turbine" means any stationary gas turbine which recovers heat from the gas turbine

exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) "Combined cycle gas turbine" means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) "Emergency gas turbine" means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) "Ice fog" means an atmospheric suspension of highly reflective ice crystals.

(g) "ISO standard day conditions" means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) "Efficiency" means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) "Peak load" means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) "Base load" means the load level at which a gas turbine is normally operated.

(k) "Fire-fighting turbine" means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) "Turbines employed in oil/gas production or oil/gas transportation" means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A "Metropolitan Statistical Area" or "MSA" as defined by the Department of Commerce.

(n) "Offshore platform gas turbines" means any stationary gas turbine located on a platform in an ocean.

(o) "Garrison facility" means any permanent military installation.

(p) "Gas turbine model" means a group of gas turbines having the same nominal air flow, combuster inlet pressure, combuster inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

§ 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart, as specified in paragraphs (b), (c), and (d) of this section, shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), and (i) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined in part (3) of this paragraph.

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0150 \left(\frac{14.4}{Y}\right) + F$$

where:

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined in part (3) of this paragraph.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-Bound Nitrogen (percent by weight)	F (NO_x percent by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	$0.04(N)$
$0.1 < N \leq 0.25$	$0.004 + 0.0067(N-0.1)$
$N > 0.25$	0.005

where:

N = the nitrogen content of the fuel (percent by weight).

or:

Manufacturers may develop custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by § 60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the Federal Register.

(b) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired except as provided in § 60.332(d) shall comply with the provisions of § 60.332(a)(1).

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of § 60.332(a)(2).

(d) Stationary gas turbines employed in oil/gas production or oil/gas transportation and not located in Metropolitan Statistical Areas; and offshore platform turbines shall comply with the provisions of § 60.332(a)(2).

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NO_x emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These

exemptions will be allowed only while the mandatory water restrictions are in effect.

§ 60.333 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by § 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

§ 60.334 Monitoring of operations.

(a) The owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water injection to control NO_x emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within ±5.0 percent and shall be approved by the Administrator.

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

(c) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with § 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under § 60.335(a).

(2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

(3) *Ice fog.* Each period during which an exemption provided in § 60.332(g) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(Sec. 114 of the Clean Air Act as amended [42 U.S.C. 1857c–9]).

§ 60.335 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.332 as follows:

(1) Reference Method 20 for the concentration of nitrogen oxides and oxygen. For affected facilities under this subpart, the span value shall be 300 parts per million of nitrogen oxides.

(i) The nitrogen oxides emission level measured by Reference Method 20 shall be adjusted to ISO standard day conditions by the following ambient condition correction factor:

$$NO_X = (NO_{X_{obs}}) \left(\frac{P_{ref}}{P_{obs}}\right)^{0.5} e^{19(H_{obs} - 0.00633)} \left(\frac{T_{AMB}}{288°K}\right)^{1.53}$$

where:

NO_x = emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.

$NO_{x_{obs}}$ = measured NO_x emissions at 15 percent oxygen, ppmv.

P_{ref} = reference combuster inlet absolute pressure at 101.3 kilopascals ambient pressure.

P_{obs} = measured combustor inlet absolute pressure at test ambient pressure.

H_{obs} = specific humidity of ambient air at test.

e = transcendental constant (2.718).

T_{AMB} = temperature of ambient air at test.

The adjusted NO_x emission level shall be used to determine compliance with § 60.332.

(ii) Manufacturers may develop custom ambient condition correction factors for each gas turbine model they manufacture in terms of combustor inlet pressure, ambient air pressure, ambient air humidity and ambient air temperature to adjust the nitrogen oxides emission level measured by the performance test as provided for in § 60.8 to ISO standard day conditions. These ambient condition correction factors shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by § 60.8. Notices of approval of custom ambient condition correction factors will be published in the **Federal Register.**

(iii) The water-to-fuel ratio necessary to comply with § 60.332 will be determined during the initial performance test by measuring NO_x emission using Reference Method 20 and the water-to-fuel ratio necessary to comply with § 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

(2) The analytical methods and procedures employed to determine the nitrogen content of the fuel being fired shall be approved by the Administrator and shall be accurate to within ±5 percent.

(b) The method for determining compliance with § 60.333, except as provided in § 60.8(b), shall be as follows:

(1) Reference Method 20 for the concentration of sulfur dioxide and oxygen or

(2) ASTM D2880–71 for the sulfur content of liquid fuels and ASTM D1072–70 for the sulfur content of gaseous fuels. These methods shall also be used to comply with § 60.334(b).

(c) Analysis for the purpose of determining the sulfur content and the nitrogen content of the fuel as required by § 60.334(b), this subpart, may be performed by the owner/operator, a service contractor retained by the owner/operator, the fuel vendor, or any other qualified agency provided that the analytical methods employed by these agencies comply with the applicable paragraphs of this section.

(Sec. 114 of the Clean Air Act as amended [42 U.S.C. 1857c-91]).

Appendix A—Reference Methods

2. Part 60 is amended by adding Reference Method 20 to Appendix A as follows:

* * * * *

Method 20—Determination of Nitrogen Oxides, Sulfur Dioxide, and Oxygen Emissions from Stationary Gas Turbines

1. Applicability and Principle

1.1 Applicability. This method is applicable for the determination of nitrogen oxides (NO_x), sulfur dioxide (SO_2), and oxygen (O_2) emissions from stationary gas turbines. For the NO_x and O_2 determinations, this method includes: (1) measurement system design criteria, (2) analyzer performance specifications and performance test procedures; and (3) procedures for emission testing.

1.2 Principle. A gas sample is continuously extracted from the exhaust stream of a stationary gas turbine; a portion of the sample stream is conveyed to instrumental analyzers for determination of NO_x and O_2 content. During each NO_x and O_2 determination, a separate measurement of SO_2 emissions is made, using Method 6, or it equivalent. The O_2 determination is used to adjust the NO_x and SO_2 concentrations to a reference condition.

2. Definitions

2.1 Measurement System. The total equipment required for the determination of a gas concentration or a gas emission rate. The system consists of the following major subsystems:

2.1.1 Sample Interface. That portion of a system that is used for one or more of the following: sample acquisition, sample transportation, sample conditioning, or protection of the analyzers from the effects of the stack effluent.

2.1.2 NO_x Analyzer. That portion of the system that senses NO_x and generates an output proportional to the gas concentration.

2.1.3 O_2 Analyzer. That portion of the system that senses O_2 and generates an output proportional to the gas concentration.

2.2 Span Value. The upper limit of a gas concentration measurement range that is specified for affected source categories in the applicable part of the regulations.

2.3 Calibration Gas. A known concentration of a gas in an appropriate diluent gas.

2.4 Calibration Error. The difference between the gas concentration indicated by the measurement system and the known concentration of the calibration gas.

2.5 Zero Drift. The difference in the measurement system output readings before and after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place and the input concentration at the time of the measurements was zero.

2.6 Calibration Drift. The difference in the measurement system output readings before and after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place and the input at the time of the measurements was a high-level value.

2.7 Residence Time. The elapsed time from the moment the gas sample enters the probe tip to the moment the same gas sample reaches the analyzer inlet.

2.8 Response Time. The amount of time required for the continuous monitoring system to display on the data output 95 percent of a step change in pollutant concentration.

2.9 Interference Response. The output response of the measurement system to a component in the sample gas, other than the gas component being measured.

3. Measurement System Performance Specifications

3.1 NO_2 to NO Converter. Greater than 90 percent conversion efficiency of NO_2 to NO.

3.2 Interference Response. Less than ± 2 percent of the span value.

3.3 Residence Time. No greater than 30 seconds.

3.4 Response Time. No greater than 3 minutes.

3.5 Zero Drift. Less than ± 2 percent of the span value.

3.6 Calibration Drift. Less than ± 2 percent of the span value.

4. Apparatus and Reagents

4.1 Measurement System. Use any measurement system for NO_x and O_2 that is expected to meet the specifications in this method. A schematic of an acceptable measurement system is shown in Figure 20-1. The essential components of the measurement system are described below:

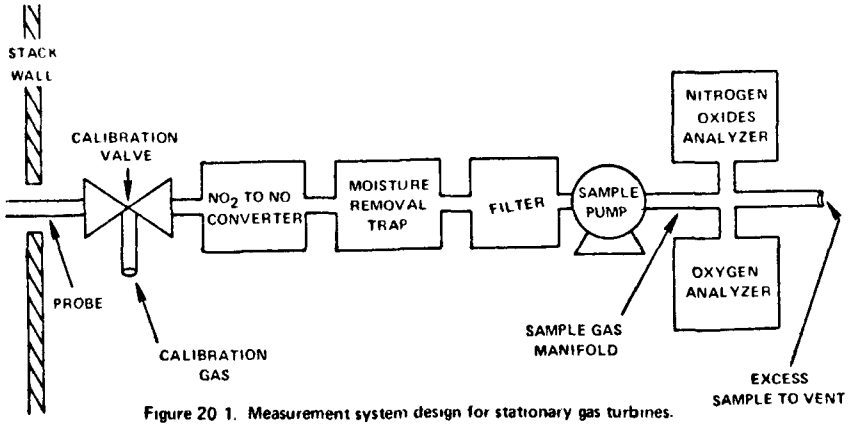


Figure 20 1. Measurement system design for stationary gas turbines.

4.1.1 Sample Probe. Heated stainless steel, or equivalent, open-ended, straight tube of sufficient length to traverse the sample points.

4.1.2 Sample Line. Heated (>95°C) stainless steel or Teflon tubing to transport the sample gas to the sample conditioners and analyzers.

4.1.3 Calibration Valve Assembly. A three-way valve assembly to direct the zero and calibration gases to the sample conditioners and to the analyzers. The calibration valve assembly shall be capable of blocking the sample gas flow and of introducing calibration gases to the measurement system when in the calibration mode.

4.1.4 NO_2 to NO Converter. That portion of the system that converts the nitrogen dioxide (NO_2) in the sample gas to nitrogen oxide (NO). Some analyzers are designed to measure NO_x as NO_2 on a wet basis and can be used without an NO_2 to NO converter or a moisture removal trap provided the sample line to the analyzer is heated (>95°C) to the inlet of the analyzer. In addition, an NO_2 to NO converter is not necessary if the NO_2 portion of the exhaust gas is less than 5 percent of the total NO_x concentration. As a guideline, an NO_2 to NO converter is not necessary if the gas turbine is operated at 90 percent or more of peak load capacity. A converter is necessary under lower load conditions.

4.1.5 Moisture Removal Trap. A refrigerator-type condenser designed to continuously remove condensate from the sample gas. The moisture removal trap is not necessary for analyzers that can measure NO_x concentrations on a wet basis; for these analyzers, (a) heat the sample line up to the inlet of the analyzers, (b) determine the moisture content using methods subject to the approval of the Administrator, and (c) correct the NO_x and O_2 concentrations to a dry basis.

4.1.6 Particulate Filter. An in-stack or an out-of-stack glass fiber filter, of the type specified in EPA Reference Method 5; however, an out-of-stack filter is recommended when the stack gas temperature exceeds 250 to 300°C.

4.1.7 Sample Pump. A nonreactive leak-free sample pump to pull the sample gas through the system at a flow rate sufficient to minimize transport delay. The pump shall be made from stainless steel or coated with Teflon or equivalent.

4.1.8 Sample Gas Manifold. A sample gas manifold to divert portions of the sample gas stream to the analyzers. The manifold may be constructed of glass, Teflon, type 316 stainless steel, or equivalent.

4.1.9 Oxygen and Analyzer. An analyzer to determine the percent O_2 concentration of the sample gas stream.

4.1.10 Nitrogen Oxides Analyzer. An analyzer to determine the ppm NO_x concentration in the sample gas stream.

4.1.11 Data Output. A strip-chart recorder, analog computer, or digital recorder for recording measurement data.

4.2 Sulfur Dioxide Analysis. EPA Reference Method 6 apparatus and reagents.

4.3 NO_x Caliberation Gases. The calibration gases for the NO_x analyzer may be NO in N_2, NO_2 in air or N_2, or NO and NO_2

in N_2. For NO_x measurement analyzers that require oxidation of NO to NO_2, the calibration gases must be in the form of NO in N_2. Use four calibration gas mixtures as specified below:

4.3.1 High-level Gas. A gas concentration that is equivalent to 80 to 90 percent of the span value.

4.3.2 Mid-level Gas. A gas concentration that is equivalent to 45 to 55 percent of the span value.

4.3.3 Low-level Gas. A gas concentration that is equivalent to 20 to 30 percent of the span value.

4.3.4 Zero Gas. A gas concentration of less than 0.25 percent of the span value. Ambient air may be used for the NO_x zero gas.

4.4 O_2 Calibration Gases. Use ambient air at 20.9 percent as the high-level O_2 gas. Use a gas concentration that is equivalent to 11–14 percent O_2 for the mid-level gas. Use purified nitrogen for the zero gas.

4.5 NO_2/NO Gas Mixture. For determining the conversion efficiency of the NO_2 to NO converter, use a calibration gas mixture of NO_2 and NO in N_2. The mixture will be known concentrations of 40 to 60 ppm NO_2 and 90 to 110 ppm NO and certified by the gas manufacturer. This certification of gas concentration must include a brief description of the procedure followed in determining the concentrations.

5. Measurement System Performance Test Procedures

Perform the following procedures prior to measurement of emissions (Section 6) and only once for each test program, i.e., the series of all test runs for a given gas turbine engine.

5.1 Calibration Gas Checks. There are two alternatives for checking the concentrations of the calibration gases. (a) The first is to use calibration gases that are documented traceable to National Bureau of Standards Reference Materials. Use *Traceability Protocol for Establishing True Concentrations of Gases Used for Calibrations and Audits of Continuous Source Emission Monitors* (Protocol Number 1) that is available from the Environmental Monitoring and Support Laboratory, Quality Assurance Branch, Mail Drop 77, Environmental Protection Agency, Research Triangle Park, North Carolina 27711. Obtain a certification from the gas manufacturer that the protocol was followed. These calibration gases are not to be analyzed with the Reference Methods. (b) The second alternative is to use calibration gases not prepared according to the protocol. If this alternative is chosen, within 1 month prior to the emission test, analyze each of the calibration gas mixtures in triplicate using *Reference Method 7* or the procedure outlined in Citation 8.1 for NO_x and use Reference Method 3 for O_2. Record the results on a data sheet (example is shown in Figure 20–2). For the low-level, mid-level, or high-level gas mixtures, each of the individual NO_x analytical results must be within 10 percent (or 10 ppm, whichever is greater) of the triplicate set average (O_2 test results must be within 0.5 percent O_2); otherwise, discard the entire set and repeat the triplicate analyses. If the average of the triplicate reference method test results is within 5 percent for NO_x gas or 0.5 percent O_2 for the O_2 gas of the calibration gas manufacturer's tag value, use the tag value; otherwise, conduct at least three additional reference method test analyses until the results of six individual NO_x runs (the three original plus three additional) agree within 10 percent (or 10 ppm, whichever is greater) of the average (O_2 test results must be within 0.5 percent O_2). Then use this average for the cylinder value.

5.2 Measurement System Preparation. Prior to the emission test, assemble the measurement system following the manufacturer's written instructions in preparing and operating the NO_2 to NO converter, the NO_x analyzer, the O_2 analyzer, and other components.

Date _____ (Must be within 1 month prior to the test period)

Reference method used _____

Sample run	Gas concentration, ppm		
	Low level[a]	Mid level[b]	High level[c]
1			
2			
3			
Average			
Maximum % deviation[d]			

[a] Average must be 20 to 30% of span value.

[b] Average must be 45 to 55% of span value

[c] Average must be 80 to 90% of span value.

[d] Must be $\leq \pm$ 10% of applicable average or 10 ppm, whichever is greater.

Figure 20-2. Analysis of calibration gases

5.3 Calibration Check. Conduct the calibration checks for both the NO_x and the O_2 analyzers as follows:

5.3.1 After the measurement system has been prepared for use (Section 5.2), introduce zero gases and the mid-level calibration gases; set the analyzer output responses to the appropriate levels. Then introduce each of the remainder of the calibration gases described in Sections 4.3 or 4.4, one at a time, to the measurement system. Record the responses on a form similar to Figure 20–3.

5.3.2 If the linear curve determined from the zero and mid-level calibration gas responses does not predict the actual response of the low-level (not applicable for the O_2 analyzer) and high-level gases within ±2 percent of the span value, the calibration shall be considered invalid. Take corrective measures on the measurement system before proceeding with the test.

5.4 Interference Response. Introduce the gaseous components listed in Table 20–1 into the measurement system separately, or as gas mixtures. Determine the total interference output response of the system to these components in concentration units; record the values on a form similar to Figure 20–4. If the sum of the interference responses of the test gases for either the NO_x or O_2 analyzers is greater than 2 percent of the applicable span value, take corrective measure on the measurement system.

Table 20–1.—*Interference Test Gas Concentration*

CO	500 ± 50 ppm.
SO_2	200 ± 20 ppm.
CO_2	10 ± 1 percent
O_2	20.9 ± 1 percent

Date of test _____

Analyzer type _____ Serial No. _____

Test gas type	Concentration, ppm	Analyzer output response	% of span

$$\% \text{ of span} = \frac{\text{Analyzer output response}}{\text{Instrument span}} \times 100$$

Figure 20 4 Interference response

Turbine type: _____ Identification number _____

Date: _____ Test number _____

Analyzer type: _____ Identification number _____

	Cylinder value, ppm or %	Initial analyzer response, ppm or %	Final analyzer responses, ppm or %	Difference: initial-final, ppm or %
Zero gas				
Low - level gas				
Mid - level gas				
High - level gas				

$$\text{Percent drift} = \frac{\text{Absolute difference}}{\text{Span value}} \times 100.$$

Figure 20-3. Zero and calibration data.

Conduct an interference response test of each analyzer prior to its initial use in the field. Thereafter, recheck the measurement system if changes are made in the instrumentation that could alter the interference response, e.g., changes in the type of gas detector.

In lieu of conducting the interference response test, instrument vendor data, which demonstrate that for the test gases of Table 20–1 the interference performance specification is not exceeded, are acceptable.

5.5 Residence and Response Time.

5.5.1 Calculate the residence time of the sample interface portion of the measurement system using volume and pump flow rate information. Alternatively, if the response time determined as defined in Section 5.5.2 is less than 30 seconds, the calculations are not necessary.

5.5.2 To determine response time, first introduce zero gas into the system at the

calibration valve until all readings are stable then, switch to monitor the stack effluent until a stable reading can be obtained. Record the upscale response time. Next, introduce high-level calibration gas into the system. Once the system has stabilized at the high-level concentration, switch to monitor the stack effluent and wait until a stable value is reached. Record the downscale response time. Repeat the procedure three times A stable value is equivalent to a change of less than 1 percent of span value for 30 seconds or less than 5 percent of the measured average concentration for 2 minutes. Record the response time data on a form similar to Figure 20–5, the readings of the upscale or downscale reponse time, and report the greater time as the "response time" for the analyzer. Conduct a response time test prior to the initial field use of the measurement system, and repeat if changes are made in the measurement system.

Date of test _____

Analyzer type _____ S/N _____

Span gas concentration _____ ppm

Analyzer span setting _____ ppm

Upscale	1 _____	seconds
	2 _____	seconds
	3 _____	seconds

Average upscale response _____ seconds

Downscale	1 _____	seconds
	2 _____	seconds
	3 _____	seconds

Average downscale response _____ seconds

System response time = slower average time = _____ seconds.

Figure 20-5 Response time

5.6 NO_2-NO Conversion Efficiency Introduce to the system, at the calibration valve assembly the NO_2/NO gas mixture (Section 4.5) Record the response of the NO_x analyzer If the instrument response indicates less than 90 percent NO_2 to NO conversion, make corrections to the measurement system and repeat the check. Alternatively, the NO_2 to NO converter check described in Title 40 Part 86 *Certification and Test Procedures for Heavy-Duty Engines for 1979 and Later Model Years* may be used. Other alternate procedures may be used with approval of the Administrator.

6. Emission Measurement Test Procedure

6.1 Preliminaries

6.1.1 Selection of a Sampling Site. Select a sampling site as close as practical to the exhaust of the turbine. Turbine geometry, stack configuration, internal baffling and point of introduction of dilution air will vary for different turbine designs. Thus, each of these factors must be given special consideration in order to obtain a representative sample. Whenever possible, the sampling site shall be located upstream of the point of introduction of dilution air into the duct. Sample ports may be located before or after the upturn elbow, in order to accommodate the configuration of the turning vanes and baffles and to permit a complete, unobstructed traverse of the stack. The sample ports shall not be located within 5 feet or 2 diameters (whichever is less) of the gas discharge to atmosphere. For supplementary-fired, combined-cycle plants, the sampling site shall be located between the gas turbine and the boiler. The diameter of the sample ports shall be sufficient to allow entry of the sample probe.

6.1.2 A preliminary O_2 traverse is made for the purpose of selecting low O_2 values. Conduct this test at the turbine condition that is the lowest percentage of peak load operation included in the program Follow the procedure below or alternative procedures subject to the approval of the Administrator may be used:

6.1.2.1 Minimum Number of Points. Select a minimum number of points as follows: (1) eight, for stacks having cross-sectional areas less than 1.5 m^2 (16.1 ft^2); (2) one sample point for each 0.2 m^2 (2.2 ft^2 of areas, for stacks of 1.5 m^2 to 10.0 m^2 (16.1–107.6 ft^2) in cross-sectional area; and (3) one sample point for each 0.4 m^2 (4.4 ft^2) of area, for stacks greater than 10.0 m^2 (107.6 ft^2) in cross-sectional area. Note that for circular ducts, the number of sample points must be a multiple of 4, and for rectangular ducts, the number of points must be one of those listed in Table 20–2; therefore, round off the number of points (upward), when appropriate.

6.1.2.2 Cross-sectional Layout and Location of Traverse Points. After the number of traverse points for the preliminary O^2 sampling has been determined, use Method 1 to located the traverse points.

6.1.2.3 Preliminary O^2 Measurement While the gas turbine is operating at the lowest percent of peak load, conduct a preliminary O^2 measurement as follows. Position the probe at the first traverse point and begin sampling The minimum sampling time at each point shall be 1 minute plus the average system response time. Determine the average steady-state concentration of O^2 at each point and record the data on Figure 20–6.

6.1.2.4 Selection of Emission Test Sampling Points Select the eight sampling points at which the lowest O^2 concentration were obtained Use these same points for all the test runs at the different turbine load conditions More than eight points may be used, if desired

Table 20-2.—*Cross-sectional Layout for Rectangular Stacks*

No. of traverse points	Matrix layout
9	3 x 3
12	4 x 3
16	4 x 4
20	5 x 4
25	5 x 5
30	6 x 5
36	6 x 6
42	7 x 6
49	7 x 7

Location: Date _____

Plant _____

City, State _____

Turbine identification:

Manufacturer _____

Model, serial number _____

Sample point	Oxygen concentration, ppm

Figure 20-6. Preliminary oxygen traverse.

6.2 NO_x and O_2 Measurement. This test is to be conducted at each of the specified load conditions. Three test runs at each load condition constitute a complete test.

6.2.1 At the beginning of each NO_x test run and, as applicable, during the run, record turbine data as indicated in Figure 20-7. Also, record the location and number of the traverse points on a diagram.

BILLING CODE 6560-01-M

6.2.2 Position the probe at the first point determined in the preceding section and begin sampling. The minimum sampling time at each point shall be at least 1 minute plus the average system response time. Determine the average steady-state concentration of O_2 and NO_x at each point and record the data on Figure 20-8.

TURBINE OPERATION RECORD

Test operator _____ Date _____

Turbine identification:
Type _____
Serial No. _____

Location:
Plant _____
City _____

Ambient temperature _____

Ambient humidity _____

Test time start _____

Test time finish _____

Fuel flow rate[a] _____

Water or steam _____
Flow rate[a]

Ambient Pressure _____

Ultimate fuel Analysis
C _____
H _____
O _____
N _____
S _____
Ash _____
H_2O _____

Trace Metals
_____
Na _____
Va _____
K _____
etc[b] _____

Operating load _____

[a]Describe measurement method, i.e., continuous flow meter, start finish volumes, etc.

[b]i.e., additional elements added for smoke suppression.

Figure 20-7. Stationary gas turbine data.

Turbine identification:

Manufacturer _____

Model, serial No. _____

Location:

Plant _____

City, State _____

Ambient temperature _____

Ambient pressure _____

Date _____

Test time - start _____

Test time - finish _____

Test operator name _____

O_2 instrument type _____
Serial No. _____

NO_x instrument type _____
Serial No. _____

Sample point	Time, min.	O_2,[a] %	NO_x,[a] ppm

[a]Average steady-state value from recorder or instrument readout.

Figure 20-8. Stationary gas turbine sample point record.

6.2.3 After sampling the last point, conclude the test run by recording the final turbine operating parameters and by determining the zero and calibration drift, as follows:

Immediately following the test run at each load condition, or if adjustments are necessary for the measurement system during the tests, reintroduce the zero and mid-level calibration gases as described in Sections 4.3, and 4.4, one at a time, to the measurement system at the calibration valve assembly. (Make no adjustments to the measurement system until after the drift checks are made). Record the analyzers' responses on a form similar to Figure 20–3. If the drift values exceed the specified limits, the test run preceding the check is considered invalid and will be repeated following corrections to the measurement system. Alternatively, the test results may be accepted provided the measurement system is recalibrated and the calibration data that result in the highest corrected emission rate are used.

6.3 SO_2 Measurement. This test is conducted only at the 100 percent peak load condition. Determine SO_2 using Method 6, or equivalent, during the test. Select a minimum of six total points from those required for the NO_x measurements; use two points for each sample run. The sample time at each point shall be at least 10 minutes. Average the O_2 readings taken during the NO_x test runs at sample points corresponding to the SO_2 traverse points (see Section 6.2.2) and use this average O_2 concentration to correct the integrated SO_2 concentration obtained by Method 6 to 15 percent O_2 (see Equation 20–1).

If the applicable regulation allows fuel sampling and analysis for fuel sulfur content to demonstrate compliance with sulfur emission unit, emission sampling with Reference Method 6 is not required, provided the fuel sulfur content meets the limits of the regulation.

7. Emission Calculations

7.1 Correction to 15 Percent Oxygen. Using Equation 20–1, calculate the NO_x and SO_2 concentrations (adjusted to 15 percent O_2). The correction to 15 percent O_2 is sensitive to the accuracy of the O_2 measurement. At the level of analyzer drift specified in the method (±2 percent of full scale), the change in the O_2 concentration correction can exceed 10 percent when the O_2 content of the exhaust is above 16 percent O_2. Therefore O_2 analyzer stability and careful calibration are necessary.

$$C_{adj} = C_{meas} \times \frac{5.9}{20.9 - \%\ O_2} \qquad \text{(Equation 20-1)}$$

Where:

C_{adj} = Pollutant concentration adjusted to 15 percent O_2 (ppm)

C_{meas} = Pollutant concentration measured, dry basis (ppm)

5.9 = 20.9 percent O_2 − 15 percent O_2, the defined O_2 correction basis

Percent O_2 = Percent O_2 measured, dry basis (%)

7.2 Calculate the average adjusted NO_x concentration by summing the point values and dividing by the number of sample points.

8. Citations

8.1 Curtis, F. A Method for Analyzing NO_x Cylinder Gases-Specific Ion Electrode Procedure, Monograph available from Emission Measurement Laboratory, ESED, Research Triangle Park, N.C. 27711, October 1978.

[FR Doc 79-27993 Filed 9-7-79; 8 45 am]

BILLING CODE 6560-01-M

102

40 CFR Part 60

[FRL 1327-8]

Standards of Performance for New Stationary Sources; General Provisions; Definitions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final Rule.

SUMMARY: This document makes some editorial changes and rearranges the definitions alphabetically in Subpart A—General Provisions of 40 CFR Part 60. An alphabetical list of definitions will be easier to update and to use.

EFFECTIVE DATE: September 25, 1979.

FOR FURTHER INFORMATION CONTACT: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5271.

SUPPLEMENTARY INFORMATION: The "Definitions" section (§ 60.2) of the General Provisions of 40 CFR Part 60 now lists 28 definitions by paragraph designations. Due to the anticipated increase in the number of definitions to be added to the General Provisions in the future, continued use of the present system of adding definitions by paragraph designations at the end of the list could become administratively cumbersome and could make the list difficult to use. Therefore, paragraph designations are being eliminated and the definitions are rearranged alphabetically. New definitions will be added to § 60.2 of the General Provisions in alphabetical order automatically.

Since this rule simply reorganizes existing provisions and has no regulatory impact, it is not subject to the procedural requirements of Executive Order 12044.

Dated: September 19, 1979.

Edward F. Tuerk,

Acting Assistant Administrator for Air, Noise, and Radiation.

40 CFR 60.2 is amended by removing all paragraph designations and by rearranging the definitions in alphabetical order as follows:

§ 60.2 Definitions.

The terms used in this part are defined in the Act or in this section as follows:

"Act" means the Clean Air Act (42 U.S.C. 1857 et seq., as amended by Pub. L. 91-604, 84 Stat. 1676).

"Administrator" means the Administrator of the Environmental Protection Agency or his authorized representative.

"Affected facility" means, with reference to a stationary source, any apparatus to which a standard is applicable.

"Alternative method" means any method of sampling and analyzing for an air pollutant which is not a reference or equivalent method but which has been demonstrated to the Administrator's satisfaction to, in specific cases, produce results adequate for his determination of compliance.

"Capital expenditure" means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable "annual asset guideline repair allowance percentage" specified in the latest edition of Internal Revenue Service Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code.

"Commenced" means, with respect to the definition of "new source" in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

"Construction" means fabrication, erection, or installation of an affected facility.

"Continuous monitoring system" means the total equipment, required under the emission monitoring sections in applicable subparts, used to sample and condition (if applicable), to analyze, and to provide a permanent record of emissions or process parameters.

"Equivalent method" means any method of sampling and analyzing for an air pollutant which has been demonstrated to the Administrator's satisfaction to have a consistent and quantitatively known relationship to the reference method, under specified conditions.

"Existing facility" means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type.

"Isokinetic sampling" means sampling in which the linear velocity of the gas entering the sampling nozzle is equal to that of the undisturbed gas stream at the sample point.

"Malfunction" means any sudden and unavoidable failure of air pollution control equipment or process equipment or of a process to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

"Modification" means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

"Monitoring device" means the total equipment, required under the monitoring of operations sections in applicable subparts, used to measure and record (if applicable) process parameters.

"Nitrogen oxides" means all oxides of nitrogen except nitrous oxide, as measured by test methods set forth in this part.

"One-hour period" means any 60-minute period commencing on the hour.

"Opacity" means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

"Owner or operator" means any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part.

"Particulate matter" means any finely divided solid or liquid material, other than uncombined water, as measured by the reference methods specified under each applicable subpart, or an equivalent or alternative method.

"Proportional sampling" means sampling at a rate that produces a constant ration of sampling rate to stack gas flow rate.

"Reference method" means any method of sampling and analyzing for an air pollutant as described in Appendix A to this part.

"Run" means the net period of time during which an emission sample is collected. Unless otherwise specified, a run may be either intermittent or continuous within the limits of good engineering practice.

"Shutdown" means the cessation of operation of an affected facility for any purpose.

"Six-minute period" means any one of the 10 equal parts of a one-hour period.

"Standard" means a standard of performance proposed or promulgated under this part.

"Standard conditions" means a temperature of 293 K (68°F) and a pressure of 101.3 kilopascals (29.92 in Hg).

"Startup" means the setting in operation of an affected facility for any purpose.

"Stationary source" means any building, structure, facility, or installation which emits or may emit any air pollutant and which contains any one or combination of the following:

(a) Affected facilities.

(b) Existing facilities.

(c) Facilities of the type for which no standards have been promulgated in this part.

(Sec. 111, 301(a), Clean Air Act as amended (42 U.S.C. 7411 and 7601(a))

[FR Doc 79-29769 Filed 9-24-79 8 45 am]

BILLING CODE 6560-01-M

103

40 CFR Part 60

[FRL 1331-5]

Standards of Performance for New Stationary Sources; Petroleum Refinery Claus Sulfur Recovery Plants; Amendment

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action deletes the requirement that a Claus sulfur recovery plant of 20 long tons per day (LTD) or less must be associated with a "small petroleum refinery" in order to be exempt from the new source performance standards for petroleum refinery Claus sulfur recovery plants. This action will result in only negligible changes in the environmental, energy, and economic impacts of the standards

EFFECTIVE DATE: October 25, 1979

ADDRESS: All comments received on the proposal are available for public inspection and copying at the EPA Central Docket Section (A-130), Room 2903B, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460. The docket number is OAQPS-79-10.

FOR FURTHER INFORMATION CONTACT: Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Background

On March 15, 1978, EPA promulgated new source performance standards for petroleum refinery Claus sulfur recovery plants. These standards did not apply to Claus sulfur recovery plants of 20 LTD or less associated with a small petroleum refinery. 40 CFR 60.100 (1978). "Small petroleum refinery" was defined as a "petroleum refinery which has a crude oil processing capacity of 50,000 barrels per stream day or less, and which is owned or controlled by a refiner with a total combined crude oil processing capacity of 137,500 barrels per stream day or less," 40 CFR 60.101(m) (1978).

On May 12, 1978, two oil companies filed a Petition for Review of these new source performance standards. One issue was whether the definition of "small petroleum refinery" was unduly restrictive.

On March 20, 1979, EPA proposed to amend the definition of "small petroleum refinery" by deleting the requirement that it be "owned or controlled by a refiner with a total combined crude oil processing capacity of 137,500 barrels per stream day (BSD) or less," 44 FR 17120. This proposal would have had a negligible effect on sulfur dioxide (SO_2) emissions, costs, and energy consumption. The oil company petitioners agreed to dismiss their entire Petition for Review if the final regulation did not differ substantively from this proposal.

EPA provided a 60 day period for comment on the proposal and the opportunity for interested persons to request a hearing. The comment period closed May 21, 1979. EPA received six written comments and no requests for a hearing

Summary of Amendment

The promulgated amendment deletes the requirement that a Claus sulfur recovery plant of 20 LTD or less must be associated with a "small petroleum refinery" in order to be exempt from the new source performance standards for such plants. Thus, the final standard will apply to any petroleum refinery Claus sulfur recovery plant of more than 20 LTD processing capacity. This amendment will apply, like the standards themselves, to affected facilities, the construction or modification of which commenced after October 4, 1976, the date the standards of performance for petroleum refinery Claus sulfur recovery plants were proposed.

Environmental, Energy, and Ecomonic Impacts

The promulgated amendment will result in a negligible increase in nationwide sulfur dioxide emissions compared to the proposed amendment and the existing standard. The promulgated amendment will also have essentially no impact on other aspects of environmental quality, such as solid waste disposal, water pollution, or noise. Finally, the promulgated amendment will have essentially no impact on nationwide energy consumption or refinery product prices.

Summary of Comments and Rationale

All six comments received were from the petroleum refinery industry. Two commenters expressed agreement with the proposal. The other four also were not opposed to the proposal, but felt the definition of "small petroleum refinery" was still too restrictive, as explained below

Two of the four argued for deletion of the 50,000 BSD refinery size cutoff and also that sulfur recovery plant size was not only a function of refinery size (as they felt EPA had apparently assumed in establishing the refinery size cutoff), but depended on such factors as the crude oil sulfur content and actual crude oil throughput.

The other two commenters, each planning to construct small Claus sulfur recovery plants, objected that the environmental benefits of subjecting small Claus sulfur recovery plants to the standards was not substantial even when a Claus sulfur recovery plant was associated with a petroleum refinery of more that 50,000 BSD capacity. EPA agrees. Accordingly, EPA believes it is appropriate under the circumstances to delete the refinery size requirement.

Thus, the promulgated standard would exempt from coverage by the standards any Claus sulfur recovery plant of 20 LTD or less. Alternatively, the standards of performance for petroleum refinery Claus sulfur recovery plants would apply to all plants of more than 20 LTD processing capacity.

Deletion of the refinery size requirement from the standards will not result in a significant increase in the emissions of SO_2 from petroleum refinery Claus sulfur recovery plants. This is due to the small number of small Claus sulfur recovery plants (i.e., 20 LTD or less capacity) that are likely to be built at refineries of more than 50,000 BSD and the fact that most of these exempted plants will still be required by State regulations to achieve 99.0 percent control of SO_2 (compared to the 99.9 percent control required for large Claus sulfur recovery plants). In many cases the exempted Claus sulfur recovery plants would be required to achieve greater than 99.0 percent control of SO_2 due to prevention of significant deterioration (PSD) requirements. This change will also result in a negligible decrease in costs and essentially no impact on energy and economic impacts, compared to the proposed amendment.

Docket

Docket No. OAQPS-79-10, containing all supporting information used by EPA, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, Room 2903B (see ADDRESS Section of this preamble).

The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process. Along with

the statement of basis and purpose of the promulgated rule and EPA responses to comments, the contents of the dockets will serve as the record in case of judicial review [Section 307(d)(a)].

Miscellaneous

The effective date of this regulation is October 25, 1979. Section 111(b)(1)(B) of the Clean Air Act provides that standards of performance become effective upon promulgation and apply to affected facilities, construction or modification of which was commenced after the date of proposal on October 4, 1976 (41 FR 43866).

EPA will review this regulation four years from the date of promulgation. This review will include an assessment of such factors as the need for integration with other programs the existence of alternative methods, enforceability, and improvements in emission control technology.

It should be noted that standards of performance for new stationary sources established under Section 111 of the Clean Air Act reflect: "* * * application of the best technological system of continuous emission reduction which [taking into consideration the cost of achieving such emission reduction, any non-air quality health and environmental impact and energy requirements] the Administrator determines has been adequately demonstrated." [Section 111(a)(1)]

Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate inachievable emission control. In fact, the Act requires (or has potential for requiring) the imposition of a more stringent emission standard in several situations.

For example, applicable costs do not play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources locating in nonattainment areas, i.e., those areas where statutorily mandated health and welfare standards are being violated. In this respect, Section 173 of the Act requires that a new or modified source constructed in an area which exceeds the National Ambient Air Quality Standard (NAAQS) must reduce emissions to the level which reflects the "lowest achievable emission rate" (LAER), as defined in Section 171(3), for such category of source. The statute defines LAER as that rate of emissions based on the following, whichever is more stringent:

(A) the most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or

(B) the most stringent emission limitation which is achieved in practice by such class or category of source. In no event can the emission rate exceed any applicable new source performance standard [Section 171(3)].

A similar situation may arise under the prevention of significant deterioration of air quality provisions of the Act (part C). These provisions require that certain sources [referred to in Section 169(1)] employ "best available control technology" [as defined in Section 169(3)] for all pollutants regulated under the Act. Best available control technology (BACT) must be determined on a case-by-case basis, taking energy, environmental, and economic impacts and costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to Section 111 (or 112) of the Act.

In all events, State implementation plans (SIP's) approved or promulgated under Section 110 of the Act must provide for the attainment and maintenance of NAAQS designed to protect public health and welfare. For this purpose, SIP's must in some cases require greater emission reductions than those required by standards of performance for new sources.

Finally, States are free under Section 116 of the Act to establish even more stringent emission limits than those established under Section 111 or those necessary to attain or maintain the NAAQS under Section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under Section 111; and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

Section 317 of the Clean Air Act requires the Administrator to, among other things, prepare an economic assessment for revisions to new source performance standards determined to be substantial. Executive Order 12044 requires certain analyses of significant regulations. Since this amendment lacks the economic impact and significance to require additional analyses, it is not subject to the above requirements.

Dated: October 16, 1979.

Douglas M. Costle,

Administrator.

Part 60 of chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. § 60.100 is amended by revising paragraph (a), as follows:

§ 60.100 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants of 20 long tons per day (LTD) or less. The Claus sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(b) * * *

2. § 60.101 is amended by revoking and reserving paragraph (m), as follows:

§ 60.101 Definitions

* * * * *

(m) [Reserved]

(Sec. 111, 301(a), Clean Air Act as amended [42 U.S.C. 7411, 7601(a)].)

[FR Doc. 79-32778 Filed 10-24-79; 8 45 am]

104

[FRL 1342-6]

Regulations for Ambient Air Quality Monitoring and Data Reporting

AGENCY: Environmental Protection Agency (EPA).

ACTION: Amendment to final rule.

SUMMARY: This action amends air quality monitoring and reporting regulations which were promulgated May 10, 1979 (44 FR 27558). The amendments correct several technical errors that were made in the promulgation notice. The amendments reflect the intent of the regulations as discussed in the preambles to the proposed (August 7, 1978, 43 FR 34892) and final regulations.

DATES: These amendments are effective November 9, 1979.

FOR FURTHER INFORMATION CONTACT: Stanley Sleva, Monitoring and Data Analysis Division, (MD-14) Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone number 919-541-5351.

SUPPLEMENTARY INFORMATION: On May 10, 1979, EPA promulgated a new 40 CFR Part 58 entitled, "Ambient Air Quality Surveillance." The new regulations consist of requirements for monitoring ambient air quality and reporting data to EPA as well as other regulations such as public reporting of a daily air quality index. The requirements replace § 51.17 and portions of § 51.7 from 40 CFR Part 51 and make necessary reference changes in Parts 51, 52, and 60. Other accompanying changes were made to Part 51, such as restructuring the unchanged portion of § 51.7 into a new subpart, adding regulations concerning public notification of air quality information, and applying quality assurance requirements to such monitoring as may be required by the prevention of significant deterioration program.

These amendments to the May 10, 1979, regulations correct technical errors which were discovered after promulgation. The corrections are consistent with the intent of the rulemaking and are therefore not being proposed.

* * *

The last correction is in Part 60. The correction involves a change of references in § 60.25. The change was proposed with the other regulations on August 7, 1978, but was inadvertently left out of the final promulgation.

* * *

Part 60 of Title 40, *Code of Federal Regulations*, is amended as follows:

Section 60.25, paragraph (e), is amended by changing the reference to a semi-annual report required by § 51.7 to an annual report required by § 51.321. As amended, § 60.25 reads as follows:

§ 60.25 Emission inventories, source surveillance, reports.

* * * * *

(e) The State shall submit reports on progress in plan enforcement to the Administrator on an annual (calendar year) basis, commencing with the first full report period after approval of a plan or after promulgation of a plan by the Administrator. Information required under this paragraph must be included in the annual report required by § 51.321 of this chapter.

* * * * *

(Sec. 110, 301(a), 319 of the Clean Air Act as amended (42 U S C 7410, 7601(a), 7619))

[FR Doc 79-34625 Filed 11-8-79 8 45 am]

105

40 CFR Part 60

[FRL 1369-3]

New Source Performance Standards; Delegation of Authority to the State of Maryland

AGENCY: Environmental Protection Agency.

ACTION: Final rulemaking.

SUMMARY: Pursuant to the delegation of authority for New Source Performance Standards (NSPS) to the State of Maryland on September 15, 1978, EPA is today amending 40 CFR 60.4, *Address*, to reflect this delegation.

EFFECTIVE DATE: December 3, 1979.

FOR FURTHER INFORMATION CONTACT: Tom Shiland, 215 597-7915.

SUPPLEMENTARY INFORMATION: A Notice announcing this delegation is published today elsewhere in this **Federal Register**. The amended 60.4 which adds the address of the Maryland Bureau of Air Quality to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on September 15, 1978, and it serves no purpose to delay the technical change of this address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended, 42 U.S.C. 7411.

Dated: November 14, 1979.

Douglas M. Costle,

Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4 paragraph (b) is amended by revising Subparagraph (V) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)-(U) * * *

(V) State of Maryland: Bureau of Air Quality and Noise Control, Maryland State Department of Health and Mental Hygiene, 201 West Preston Street, Baltimore, Maryland 21201.

106

40 CFR Part 60

[FRL 1353-2]

Standards of Performance for New Stationary Sources; Delegation of Authority to State of Delaware

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This document amends 40 CFR 60.4 to reflect delegation to the State of Delaware of authority to implement and enforce certain Standards of Performance for New Stationary Sources.

EFFECTIVE DATE: December 7, 1979.

FOR FURTHER INFORMATION CONTACT: Joseph Arena, Environmental Scientist, Air Enforcement Branch, Environmental Protection Agency, Region III, 6th and Walnut Streets, Philadelphia, Pennsylvania 19106, Telephone (215) 597-4561.

SUPPLEMENTARY INFORMATION:

I. Background

On October 5, 1978, the State of Delaware requested delegation of authority to implement and enforce certain Standards of Performance for New Stationary Sources for Sulfuric Acid Plants. The request was reviewed and on October 9, 1979 a letter was sent to John E. Wilson III, Acting Secretary, Department of Natural Resources and Environmental Control, approving the delegation and outlining its conditions The approval letter specified that if Acting Secretary Wilson or any other representatives had any objections to the conditions of delegation they were to respond within ten (10) days after receipt of the letter. As of this date, no objections have been received.

II. Regulations Affected by this Document

Pursuant to the delegation of authority for certain Standards of Performance for New Stationary Sources to the State of Delaware, EPA is today amending 40 CFR 60.4, *Address*, to reflect this delegation. A Notice announcing this delegation is published today in the Notices Section of this Federal Register. The amended § 60.4, which adds the address of the Delaware Department of Natural Resources and Environmental Control, to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

III. General

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on October 9, 1979, and it serves no purpose to delay the technical change of this address to the Code of Federal Regulations

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended, 42 U.S.C. 7411.

Dated: December 3, 1979.

Douglas M. Costle,

Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. In § 60.4, paragraph (b) is amended by revising subparagraph (I) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)-(H) * * *

(I) State of Delaware (for fossil fuel-fired steam generators; incinerators; nitric acid plants, asphalt concrete plants; storage vessels for petroleum liquids; sulfuric acid plants; and sewage treatment plants only.

Delaware Department of Natural Resources and Environmental Control, Edward Tatnall Building, Dover, Delaware 19901.

[FR Doc 79-37655 Filed 12-6-79, 8:45 am]

107

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1366-3]

Standards of Performance for New Stationary Sources; Adjustment of the Opacity Standard for a Fossil Fuel-Fired Steam Generator

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action adjusts the NSPS opacity standard (40 CFR Part 60, Subpart D) applicable to Southwestern Public Service Company's Harrington Station Unit #1 in Amarillo, Texas. The action is based upon Southwestern's demonstration of the conditions that entitle it to such an adjustment under 40 CFR 60.11(e).

EFFECTIVE DATE: December 28, 1979.

ADDRESS: Docket No. EN-79-13, containing material relevant to this rulemaking, is located in the U.S. Environmental Protection Agency, Central Docket Section, Room 2903 B, 401 M St., SW., Washington, D.C. 20460. The docket may be inspected between 8 a.m. and 4 p.m. on weekdays, and a reasonable fee may be charged for copying.

The docket is an organized and complete file of all the information submitted to or otherwise considered by the Administrator in the development of this rulemaking. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process.

FOR FURTHER INFORMATION CONTACT: Richard Biondi, Division of Stationary Source Enforcement (EN-341), Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460, telephone No. 202-755-2564.

SUPPLEMENTARY INFORMATION:

Background

The standards of performance for fossil fuel-fired steam generators as promulgated under Subpart D of Part 60 on December 23, 1971 (36 FR 24876) and amended on December 5, 1977 (42 FR 61537) allow emissions of up to 20% opacity (6-minute average), except that 27% opacity is allowed for one 6-minute period in any hour. This standard also requires continuous opacity monitoring and requires reporting as excess emissions all hourly periods during which there are two or more 6-minute periods when the average opacity exceeds 20%.

On December 15, 1977, Southwestern Public Service Company (SPSC) of Amarillo, Texas, petitioned the Administrator under 40 CFR 60.11(e) to adjust the 20% opacity standard applicable to its Harrington Station coal-fired Unit #1 in Amarillo, Texas. The Administrator proposed, on June 29, 1979 (44 FR 37960), to grant the petition for adjustment, concluding that SPSC had demonstrated the presence at its Harrington Station Unit #1 of the conditions that entitle it to such relief, as specified in 40 CFR 60.11(e)(3).

These final regulations are identical to the proposed ones. EPA hereby grants SPSC's petition for adjustment for Harrington Station Unit #1 from compliance with the opacity standard of 40 CFR 60.42(a)(2). As an alternative, SPSC shall not cause to be discharged into the atmosphere from the Harrington Station Unit #1 any gases which exhibit greater than 35% opacity (6-minute average), except that a maximum of 42% opacity shall be permitted for not more than one 6-minute period in any hour. This adjustment will not relieve SPSC of its obligation to comply with any other federal, state or local opacity requirements, or particulate matter, SO_2 or NO_x control requirements.

Comments

Two comment letters were received, both from industry and both supporting the proposed action. One industry representative approved of EPA efforts to adjust NSPS to account for well-known opacity difficulties found in large steam electric generating units which have hot side electrostatic precipitators and combust low-sulfur western coal.

A second industry representative suggested that the use of Best Available Control Technology on coal-fired units has not assured compliance with applicable opacity standards, and that opacity standards do not complement standards for particulate emissions. EPA disagrees with this comment. Violations of opacity standards generally reflect violations of mass emission standards, and EPA will continue to impose opacity standards as a valued tool in insuring proper operation and maintenance of air pollution control devices.

Miscellaneous

This revision is promulgated under the authority of Section 111 and 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411 and 7601(a)).

Dated: December 17, 1979.

Douglas M. Costle,

Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

40 CFR part 60 is amended as follows:

Subpart D—Standards of Performance for Fossil Fuel-Fired Steam Generators

1. Section 60.42 is amended by adding paragraph (b)(1) as follows:

§ 60.42 Standard for particulate matter.

(a) * * *

(b)(1) On and after (the date of publication of this amendment), no owner or operator shall cause to be discharged into the atmosphere from the Southwestern Public Service Company's Harrington Station Unit #1, in Amarillo, Texas, any gases which exhibit greater than 35% opacity, except that a maximum of 42% opacity shall be permitted for not more than 6 minutes in any hour.

(Sec. 111, 301(a), Clean Air Act as amended (42, U.S.C. 7411, 7601))

2. Section 60.45(g)(1) is amended by adding paragraph (i) as follows:

§ 60.45 Emission and fuel monitoring.

* * * * *

(g) * * *

(1) * * *

(i) For sources subject to the opacity standard of § 60.42(b)(1), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.

[FR Doc. 79-39509 Filed 12-27-79 8:45 am]

108

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1392-6]

Standards of Performance for New Stationary Sources; Delegation of Authority to Commonwealth of Pennsylvania

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This document amends 40 CFR 60.4 to reflect delegation to the Commonwealth of Pennsylvania for authority to implement and enforce certain Standards of Performance for New Stationary Sources.

EFFECTIVE DATE: January 16, 1980.

FOR FURTHER INFORMATION CONTACT:
Joseph Arena, Environmental Scientist, Air Enforcement Branch, Environmental Protection Agency, Region III, 6th and Walnut Streets, Philadelphia, Pennsylvania 19106, Telephone (215) 597–4561.

SUPPLEMENTARY INFORMATION:

I. Background

On October 1, 1979, the Commonwealth of Pennsylvania requested delegation of authority to implement and enforce certain Standards of Performance for New Stationary Sources. The request was reviewed and on December 7, 1979 a letter was sent to Clifford L. Jones, Secretary, Department of Environmental Resources, approving the delegation and outlining its conditions. The approval letter specified that if Secretary Jones or any other representatives had any objections to the conditions of delegation they were to respond within ten (10) days after receipt of the letter. As of this date, no objections have been received.

II. Regulations Affected by This Document

Pursuant to the delegation of authority for Standards of Performance for New Stationary Sources to the Commonwealth of Pennsylvania, EPA is today amending 40 CFR 60.4, *Address,* to reflect this delegation. A Notice announcing this delegation is published today in the **Federal Register**. The amended § 60.4, which adds the address of the Pennsylvania Department of Environmental Resources, to which all reports, requests, applications, submittals, and communications to the Administrator pursuant to this part must also be addressed, is set forth below.

III. General

The Administrator finds good cause for foregoing prior public notice and for making this rulemaking effective immediately in that it is an administrative change and not one of substantive content. No additional substantive burdens are imposed on the parties affected. The delegation which is reflected by this administrative amendment was effective on December 7, 1979, and it serves no purpose to delay the technical change of this address to the Code of Federal Regulations.

This rulemaking is effective immediately, and is issued under the authority of Section 111 of the Clean Air Act, as amended, 42 U.S.C. 7411.

Dated: December 7, 1979.

R. Sarah Compton,

Director, Enforcement Division.

Part 60 of Chapter I, Title 40 of the *Code of Federal Regulations* is amended as follows:

1. In § 60.4, paragraph (b) is amended by revising subparagraph (OO) to read as follows:

§ 60.4 Address.

* * * * *

(b) * * *

(A)–(NN) * * *

(OO) Commonwealth of Pennsylvania: Department of Environmental Resources, Post Office Box 2063, Harrisburg, Pennsylvania 17120.

[FR Doc. 80-1468 Filed 1-15-80; 8:45 am]

109

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1374-2]

Standards of Performance for New Stationary Sources; Modification, Notification, and Reconstruction; Amendment and Correction

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This amendment revokes the bubble concept as a means of determining what constitutes a "modified" source for the purpose of applying new source performance standards promulgated under the Clean Air Act. The United States Court of Appeals for the District of Columbia Circuit rejected the bubble concept in ASARCO v. EPA, 578 F.2d 319. The intent of this action is to comply with the Court's ruling. This action also amends the definition of "capital expenditure" and updates a statutory reference.

EFFECTIVE DATE: January 23, 1980.

FOR FURTHER INFORMATION CONTACT:
Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD–13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541–5271.

SUPPLEMENTARY INFORMATION:

Background

On December 16, 1975 (40 FR 58416), EPA promulgated amendments to the general provisions of 40 CFR Part 60. The purpose of those amendments was, in part, to clarify the definition of "modification" in the Clean Air Act (hereafter referred to as the Act) with regard to a stationary source. The general provisions of 40 CFR Part 60 apply to all standards of performance for new, modified, and reconstructed stationary sources promulgated under section 111 of the Act.

"Modification" is defined in those amendments as any physical change in the method of operation of an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted. "Existing facility" means any apparatus of the type for which a standard of performance is promulgated in 40 CFR Part 60, but the construction or modification of which was commenced before the date of proposal of that standard. Upon modification, an existing facility becomes an "affected facility," the basic unit to which a standard of performance applies. Depending on the circumstances of each particular regulation, EPA may designate an entire plant as an affected facility or an individual production process or piece of equipment within a plant as an affected facility.

The amendments to the general provisions of 40 CFR Part 60 also expanded the statutory definition of "stationary source" to reflect EPA's interpretation of the language of the Act. "Stationary source" is defined in the Act as a "building, facility, or installation which emits or may emit any air pollutant" [section 111(a)(3)]. The amendments expanded this definition with the addition, "and which contains any one or combination of the following:

(1) Affected facilities.

(2) Existing facilities.

(3) Facilities of the type for which no standards have been promulgated in this part."

Thus, a distinction was made between "affected facility," any apparatus to which a standard applies, and "stationary source," which could be a combination of affected, existing, and other facilities.

Based on these interpretive definitions, § 60.14(d) of the amendments allowed an existing facility to undergo a physical or operational change but not be considered modified if emission increases associated with the physical or operational change were offset by emission decreases of the same pollutant from other affected and existing facilities at the same stationary source. This is referred to as the "bubble concept."

In effect, a "bubble" could be placed over an entire plant when determining if

a physical or operational change to an existing facility within the plant constituted a modification. Emissions of a pollutant from an existing facility could increase as a result of a physical or operational change but that facility would not be deemed "modified" as long as emissions of that pollutant coming out of the "bubble" over all affected and existing facilities at the plant did not increase.

EPA did not extend the bubble concept to new-facility construction at existing plant sites.

Challenges to the bubble concept

The Sierra Club challenged EPA's use of the bubble concept in determining if a modification of an existing facility had taken place for the purpose of applying standards of performance for new, modified, and reconstructed stationary sources promulgated under section 111 of the Act. The Sierra Club contended that the interpreted definition of "stationary source" promulgated by EPA, and essential to EPA's use of the bubble concept, was inconsistent with the language of section 111 of the Act. Sierra Club argued that the Act defines a stationary source as an individual building, structure, facility or installation as distinguished from a combination of such units. Sierra Club claimed that once EPA had chosen the affected facility to which standards of performance apply, it could not subsequently examine a combination of existing and affected facilities for the purpose of determining if a particular existing facility had been modified, and was therefore subject to standards.

ASARCO also challenged this use of the bubble concept by EPA, but for a different reason. ASARCO claimed that the bubble concept should be extended to cover new source construction at existing plant sites rather than to modifications only.

In a decision rendered January 27, 1978, the United States Court of Appeals for the District of Columbia Circuit agreed with the Sierra Club and rejected the bubble concept as a means of determining if a modification to an existing facility had occurred for the purpose of applying standards of performance under section 111 of the Act (ASARCO v. EPA, 578 F.2d 319). The Court held that EPA had no authority to change the basic unit to which the NSPS apply from a single building, structure, facility or installation as specified in the Act to a combination of such units. In addition, the Court ruled that since EPA's use of the bubble concept for determining modifications was illegal to begin with, the bubble concept could not be extended to cover new sources as requested by industry.

In response to the Court's decision, EPA is, with this action, deleting the portions of § 60.14 of the general provisions of 40 CFR Part 60 which implement the bubble concept. The definition of "stationary source" in § 60.2 is also deleted. For the purposes of regulations promulgated in 40 CFR Part 60, the term "stationary source" will hereafter have the same meaning as in the Act.

Miscellaneous

The definition of "capital expenditure" in § 60.2 is being amended with the qualification that when computing the total expenditure for a physical or operational change to an existing facility, it must not be reduced by any "excluded additions" as defined in IRS Publication 534, as would be done for tax purposes. This qualification was noted in the preamble to the original regulation but not included in the regulation text as intended.

Finally, the reference to "section 119(d)(5)" of the Act in § 60.14(e)(4) is changed to "section 111(a)(8)" to reflect changes in the 1977 Clean Air Act Amendments (Public Law 95-95, August 7, 1977).

Since these actions reflect the mandate of the Court, correct an unintentional omission, and update a statutory reference, notice and public comment thereon is unnecessary and good cause exists for making them effective immediately.

Dated: January 16, 1980.

Douglas M. Costle,

Administrator.

40 CFR Part 60 is amended as follows:

1. Section 60.2 is amended by deleting the definition of "Stationary source" and by revising the definition of "Capital expenditure" as follows:

§ 60.2 Definitions.

* * * * *

"Capital expenditure" means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable "annual asset guideline repair allowance percentage" specified in the latest edition of Internal Revenue Service (IRS) Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code. However, the total expenditure for a physical or operational change to an existing facility must not be reduced by any "excluded additions" as defined in IRS Publication 534, as would be done for tax purposes.

* * * * *

§ 60.7 [Amended]

2. In § 60.7, the first sentence in paragraph (a)(4) is amended by deleting the phrase, " and the exemption is not denied under § 60.14(d)(4)."

§ 60.14 [Amended]

3. In § 60.14, the first sentence of paragraph (a) is amended, paragraph (d) is revoked and reserved, the last sentence of paragraph (e)(4) is amended, and paragraph (g) is amended as follows:

§ 60.14 Modification.

(a) Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. * * *

* * * * *

(d) [Reserved]

(e) * * *

(4) * * * Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

* * * * *

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in paragraph (a) of this section, compliance with all applicable standards must be achieved.

(Sec. 111, 301(a) of the Clean Air Act as amended [42 U.S.C. 7411, 7601(a)]).

[FR Doc 80-2122 Filed 1-22-80; 8:45 am]

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1404-6]

Standards of Performance for New Stationary Sources; Electric Utility Steam Generating Units; Decision in Response to Petitions for Reconsideration

AGENCY: Environmental Protection Agency (EPA).

ACTION: Denial of Petitions for Reconsideration of Final Regulations.

SUMMARY: The Environmental Defense Fund, Kansas City Power and Light Company, Sierra Club, Sierra Pacific Power Company and Idaho Power Company, State of California Air Resources Board, and Utility Air Regulatory Group submitted petitions for reconsideration of the revised new source performance standards for electric utility steam generating units that were promulgated on June 11, 1979 (44 FR 33580). The petitions were evaluated collectively since the petitioners raised several overlapping issues. When viewed collectively, the petitioners sought reconsideration of the standards of performance for sulfur dioxide (SO_2), particulate matter, and nitrogen oxides (NO_x). In denying the petitions, the Administrator found that the petitioners had failed to satisfy the statutory requirements of section 307(d)(7)(B) of the Clean Air Act. That is, the petitioners failed to demonstrate either (1) that it was impractical to raise their objections during the period for public comment or (2) that the basis of their objection arose after the close of the period for public comment and the objection was of central relevance to the outcome of the rule. This notice also responds to certain procedural issues raised by the Environmental Defense Fund (EDF). It should be noted that the Natural Resources Defense Council (NRDC) filed a July 9, 1979, letter in which they concurred with the procedural issues raised by EDF.

DATES: Effective February 6, 1980.

Interested persons may advise the Agency of any technical errors by March 7, 1980.

ADDRESSES: EPA invites information from interested persons. This information should be sent to: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5271.

Docket Number OAQPS-78-1 contains all supporting materials used by EPA in developing the standards, including public comments and materials pertaining to the petitions for reconsideration. The docket is available for public inspection and copying between 9:00 a.m. and 4:00 p.m., Monday through Friday at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Background

On September 19, 1978, pursuant to Section 111 of the Clean Air Act Amendments of 1977, EPA proposed revised standards of performance to limit emissions of sulfur dioxide (SO_2), particulate matter, and nitrogen oxides (NO_x) from new, modified, and reconstructed electric utility steam generating units (43 FR 42154). A public hearing was held on December 12 and 13, 1978. In addition, on December 8, 1978, EPA published additional information on the proposed rule (43 FR 57834). In this notice, the Administrator set forth the preliminary results of the Agency's analysis of the environmental, economic, and energy impacts associated with several alternative standards. This analysis was also presented at the public hearing on the proposed standards. The public comment period was extended until January 15, 1979, to allow for comments on this information.

After the Agency had carefully evaluated the more than 600 comment letters and related documents, the Administrator signed the final standards on June 1, 1979. In turn, they were promulgated in the **Federal Register** on June 11, 1979.

On June 1, 1979, the Sierra Club filed a petition for judicial review of the standards with the United States Court of Appeals for the District of Columbia. Additional petitions were filed by Appalachian Power Company, et al., the Environmental Defense Fund, and the State of California Air Resources Board before the close of the filing period on August 10, 1979.

In addition, pursuant to section 307(d)(7)(B) of the Clean Air Act, the Environmental Defense Fund, Kansas City Power and Light Company, Sierra Club, Sierra Pacific Power Company and Idaho Power Company, State of California Air Resources Board, and Utility Air Regulatory Group petitioned the Administrator for reconsideration of the revised standards.

Section 307(d)(7)(B) of the Act provides that:

> Only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. If the Administrator refuses to convene such a proceeding, such person may seek review of such refusal in the United States Court of Appeals for the appropriate circuit (as provided in subsection (b)).

The Administrator's findings and responses to the issues raised by the petitioners are presented in this notice.

Summary of Standards

Applicability

The standards apply to electric utility steam generating units capable of firing more than 73 MW (250 million Btu/hour) heat input of fossil fuel, for which construction is commenced after September 18, 1978. Industrial cogeneration facilities that sell less than 25 MW of electricity, or less than one-third of their potential electrical output capacity, are not covered. For electric utility combined cycle gas turbines, applicability of the standards is determined on the basis of the fossil-fuel fired to the steam generator exclusive of the heat input and electrical power contribution of the gas turbine.

SO_2 Standards

The SO_2 standards are as follows:

(1) Solid and solid-derived fuels (except solid solvent refined coal): SO_2 emissions to the atmosphere are limited to 520 ng/J (1.20 lb/million Btu) heat input, and a 90 percent reduction in potential SO_2 emissions is required at all times except when emissions to the atmosphere are less than 260 ng/J (0.60 lb/million Btu) heat input. When SO_2 emissions are less than 260 ng/J (0.60 lb/million Btu) heat input, a 70 percent reduction in potential emissions is required. Compliance with the emission

limit and percent reduction requirements is determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average. The percent reduction is computed on the basis of overall SO_2 removed by all types of SO_2 and sulfur removal technology, including flue gas desulfurization (FGD) systems and fuel pretreatment systems (such as coal cleaning, coal gasification, and coal liquefaction). Sulfur removed by a coal pulverizer or in bottom ash and fly ash may be included in the computation.

(2) Gaseous and liquid fuels not derived from solid fuels: SO_2 emissions into the atmosphere are limiteed to 340 ng/J (0.80 lb/million Btu) heat input, and a 90 percent reduction in potential SO_2 emissions is required. The percent reduction requirement does not apply if SO_2 emissions into the atmosphere are less than 86 ng/J (0.20 lb/million Btu) heat input. Compliance with the SO_2 emission limitation and percent reduction is determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average.

(3) Anthracite coal: Electric utility steam generating units firing anthracite coal alone are exempt from the percentage reduction requirement of the SO_2 standard but are subject to the 520 ng/J (1.20 lb/million Btu) heat input emission limit on a 30-day rolling average, and all other provisions of the regulations including the particulate matter and NO_x standards.

(4) Noncontinental areas: Electric utility steam generating units located in noncontinental areas (State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Marina Islands) are exempt from the percentage reduction requirement of the SO_2 standard but are subject to the applicable SO_2 emission limitation and all other provisions of the regulations including the particulate matter and NO_x standards.

(5) Resource recovery facilities: Resource recovery facilities which incorporate electric utility steam generating units that fire less than 25 percent fossil-fuel on a quarterly (90-day) heat input basis are not subject to the percentage reduction requirements but are subject to the 520 ng/J (1.20 lb/million Btu) heat input emission limit. Compliance with the emission limit is determined on a continuous basis using continuous monitoring to obtain a 30-day rolling average. In addition, such facilities must monitor and report their heat input by fuel type.

(6) Solid solvent refined coal: Electric utility steam generating units firing solid solvent refined coal (SRC I) are subject to the 520 ng/J (1.20 lb/million Btu) heat input emission limit (30-day rolling average) and all requirements under the NO_x and particulate matter standards. Compliance with the emission limit is determined on a continuous basis using a continuous monitor to obtain a 30-day rolling average. The percentage reduction requirement, which is obtained at the refining facility itself, is 85 percent reduction in potential SO_2 emissions on a 24-hour (daily) averaging basis. Compliance is to be determined by Method 19. Initial full-scale demonstration facilities may be granted a commercial demonstration permit establishing a requirement of 80 percent reduction in potential emissions on a 24-hour (daily) basis.

Particulate Matter Standards

The particulate matter standard limits emissions to 13 ng/J (0.03 lb/million Btu) heat input. The opacity standard limits the opacity of emissions to 20 percent (6-minute average). The standards are based on the performance of a well-designed and operated baghouse or electrostatic precipitator.

NO_x Standards

The NO_x standards are based on combustion modification and vary according to the fuel type. The standards are:

(1) 86 ng/J (0.20 lb-million Btu) heat input from the combustion of any gaseous fuel, except gaseous fuel derived from coal;

(2) 130 ng/J (0.30 lb/million Btu) heat input from the combustion of any liquid fuel, except shale oil and liquid fuel derived from coal;

(3) 210 ng/J (0.50 lb/million Btu) heat input from the combustion of subbituminous coal, shale oil, or any solid, liquid, or gaseous fuel derived from coal;

(4) 340 ng/J (0.80 lb/million Btu) heat input from the combustion in a slag tap furnace of any fuel containing more than 25 percent, by weight, lignite which has been mined in North Dakota, South Dakota, or Montana;

(5) Combustion of a fuel containing more than 25 percent, by weight, coal refuse is exempt from the NO_x standards and monitoring requirements; and

(6) 260 ng/J (0.60 lb/million Btu) heat input from the combustion of anthracite coal, bituminous coal, or any other solid fuel not specified under (3), (4), or (5).

Continuous compliance with the NO_x standards is required, based on a 30-day rolling average. Also, percent reductions in uncontrolled NO_x emission levels are required. The percent reductions are not controlling, however, and compliance with the NO_x emission limits will assure compliance with the percent reduction requirements.

Emerging Technologies

The standards include provisions which allow the Administrator to grant commercial demonstration permits to allow less stringent requirements for the initial full-scale demonstration plants of certain technologies. The standards include the following provisions:

(1) Facilities using SRC I are subject to an emission limitation of 520 ng/J (1.20 lb/million Btu) heat input, based on a 30-day rolling average, and an emission reduction requirement of 85 percent, based on a 24-hour average. However, the percentage reduction allowed under a commercial demonstration permit for the initial full-scale demonstration plant using SRC I would be 80 percent (based on a 24-hour average). The plant producing the SRC I would monitor to ensure that the required percentage reduction (24-hour average) is achieved and the power plant using the SRC I would monitor to ensure that the 520 ng/J heat input limit (30-day rolling average) is achieved.

(2) Facilities using fluidized bed combustion (FBC) or coal liquefaction would be subject to the emission limitation and percentage reduction requirement of the SO_2 standard and to the particulate matter and NO_x standards. However, the reduction in potential SO_2 emissions allowed under a commercial demonstration permit for the initial full-scale demonstration plants using FBC would be 85 percent (based on a 30-day rolling average). The NO_x emission limitation allowed under a commercial demonstration permit for the initial full-scale demonstration plants using coal liquefaction would be 300 ng/J (0.70 lb/million Btu) heat input, based on a 30-day rolling average.

(3) No more than 15,000 MW equivalent electrical capacity would be allotted for the purpose of commercial demonstration permits. The capacity will be allocated as follows:

Technology	Pollutant	Equivalent electrical capacity MW
Solid solvent-refined coal	SO_2	6,000-10,000
Fluidized bed combustion (atmospheric)	SO_2	400-3,000
Fluidized bed combustion (pressurized)	SO_2	400-1,200
Coal liquefaction	NO_x	750-10,000

Compliance Provisions

Continuous compliance with the SO_2 and NO_x standards is required and is to be determined with continuous emission monitors. Reference methods or other approved procedures must be used to supplement the emission data when the

continuous emission monitors malfunction in order to provide emission data for at least 18 hours of each day for at least 22 days out of any 30 consecutive days of boiler operation.

A malfunctioning FGD system may be bypassed under emergency conditions. Compliance with the particulate standard is determined through performance tests. Continuous monitors are required to measure and record the opacity of emissions. The continuous opacity data will be used to identify excess emissions to ensure that the particulate matter control system is being properly operated and maintained.

Issues Raised in the Petitions for Reconsideration

1. SO_2 Maximum Emission Limitation of 520 ng/J (1.2 lb/Million Btu) Heat Input

The Environmental Defense Fund (EDF), Sierra Club, and State of California Air Resources Board (CARB) requested that a proceeding be convened to reconsider the maximum SO_2 emission limitation of 520 ng/J (1.2 lb/million Btu) heat input. In their petition, EDF set forth several procedural questions as the basis for their request. First, they maintained that they did not have the opportunity to comment on certain information which was submitted to EPA by the National Coal Association at an April 5, 1979, meeting and in subsequent correspondence. The information pertained to the impacts that different emission limitations will have on coal production in the Midwest and Northern Appalachia. They argued that this information materially influenced the Administrator's final decision. Further, they maintained that the Administrator's decision in setting the emission limitation was based on *ex parte* communications and improper congressional pressure.

The Sierra Club also raised objections to information developed during the post-comment period. They cited the information supplied by the National Coal Association, and the EPA staff analysis of the impact that different emission limitations would have on burnable coal reserves. In addition, they challenged the assumption that conservatism in utility perceptions of scrubber performance could create a significant disincentive against the burning of high-sulfur coal reserves. The Sierra Club maintained that this information is of "central relevance" since it formed the basis of the establishment of the final emission limitation and that the Sierra Club was denied the opportunity to comment on this information. Finally, the Sierra Club and CARB subscribed fully to arguments presented by EDF concerning ex parte communications.

Background

The potential impact that the emission limitation may have on high-sulfur coal reserves did not arise for the first time in the post-comment period. It was an issue throughout the rulemaking. In the proposal, the Agency stated that two factors had to be taken into consideration when selecting the emission limitation—FGD efficiency and the impact of the emission limitation on high-sulfur coal reserves (43 FR 42160, middle column). The proposal also indicated that, in effect, scrubber performance determines the maximum sulfur content of coals that can be fired in compliance with emission limitation even when coal preparation is employed. From the discussion it is clear that the Administrator recognized that midwestern high-sulfur coal reserves could be severely impacted if the emission limitation was not selected with care (43 FR 42160, middle column). In addition, the Administrator also specifically sought comment on the related question of new coal production as it pertained to consideration of coal impacts in the final decision (43 FR 42155, right column).

At the December 1978 public hearing on the proposed standards, the Agency specifically sought to solicit information on the impact that lower SO_2 emission limits (below 520 ng/J (1.2 lb/million Btu) heat input) would have on high-sulfur coal reserves. In response to questions from an EPA panel member and the audience, Mr. Hoff Stauffer of ICF, Inc. (an EPA consultant) testified that the potential impact of lower emission limitations on high-sulfur coal reserves would be greater in certain states than was indicated by the results of the macroeconomic analysis conducted by his firm. He added further that if the degree of reduction achievable through coal preparation or scrubbers changed from the values assumed in the analysis (35 percent for coal preparation on high-sulfur coal and 90 percent for scrubbers) the coal impacts would vary accordingly. That is, if greater reduction could be achieved by either coal preparation or by scrubbers the impacts would be reduced. Conversely, if the degree of reduction achievable by either coal preparation or scrubbers was less than the values assumed, the impacts would be more severe (public hearing transcript, December 12, 1978, pages 46–47).

The subject was broached again when Mr. Richard Ayres, representing the Natural Resources Defense Council and serving as introductory spokesperson for other public health and environmental organizations, was asked by the panel what effect lowering the emission limitation would have on local high-sulfur coal reserves. Mr. Ayres responded that a lower emission limitation may have the effect of requiring certain coals to be scrubbed more than required by the standard. He added that the utilities would have an economic choice of either buying local high-sulfur coal and scrubbing more or buying lower-sulfur coal which may not be local and scrubbing less. He further indicated that it was not clear that a lower limitation would have the effect of precluding any coal. In doing so, he noted that the "conclusion depended entirely on assumptions about the possible emission efficiencies of scrubbers." Finally, Mr. Ayres was asked whether as long as production in a given region increased that the requirement of the Act to maximize the use of local coal was satisfied. He responded that it was a "matter of degree" and that he would not say as long as production in a given region did not decline the statute was served (public hearing transcript, December 12, 1978, pages 77–80).

Mr. Robert Rauch, representing the Environmental Defense Fund, also recognized in his testimony that lowering the emission limitation to the level recommended by EDF (340 ng/J (0.8 lb/million Btu) heat input) would adversely impact high-sulfur coal reserves. In his testimony he stated "Adoption of the proposed lower ceiling would result in the exclusion of certain high-sulfur coal reserves from use in power plants subject to the revised standard." He added that the use of adipic acid and other slurry additives would enhance scrubber performance, thereby alleviating the impacts on high-sulfur coal (public hearing transcript, December 13, 1978, pages 189–191).

Mr. Joseph Mullan of the National Coal Association testified in response to a question from the hearing panel that lowering the emission limitation from 520 ng/J (1.2 lb/million Btu) heat input would preclude the use of certain high-sulfur coals. He added that the National Coal Association would furnish data on such impacts (public hearing transcript, December 13, 1978, page 246).

Turning now to the written comments on the proposed standard submitted jointly by the Natural Resources Defense Council and the Environmental Defense Fund, we see that they carefully assessed the potential impacts on high-sulfur coal reserves that could result

from various emission limitations. They concluded, "Generally, the higher the percent removal requirement, the smaller the percentage of coal reserves which are effectively eliminated for use by utility generating units." They went on to argue that if their recommended standard of 95 percent reduction in potential SO_2 emission was accepted a lower emission limitation could be adopted without adverse impacts on coal reserves (OAQPS–78–1, IV–D–631, page V–128).

Rationale for the Maximum Emission Limit

The testimony presented at the public hearing and the written comments served to confirm the Agency's initial position that scrubber performance and potential impacts on high-sulfur coal reserves had to be carefully considered when establishing the emission limitation. Meanwhile, it became apparent that the analysis performed by EPA's consultant on emission limits below 520 ng/J (1.2 lb/million Btu) heat input might not fully reflect the impacts on major high-sulfur coal production areas. This finding was evident by study of the consultant's report (OAQPS–78–1, IV–A–5, Appendix D) which showed that the model used to estimate coal production in Appalachia and the Midwest was relatively insensitive to broad variations in the emission ceiling. The Agency then concluded that the macroeconomic model was adequate for assessing national impacts on coal use, but lacked the specificity to assess potential dislocations in specific coal production regions. In effect the analysis tended to mask the impacts in specific coal producing regions through aggregation. Concern was also raised as to the validity of the modeling assumption that a 35 percent reduction in potential SO_2 emissions can be achieved by coal washing on all high-sulfur coal reserves.

In view of these concerns, EPA concluded shortly after the close of the comment period that additional analysis was needed to support the final emission limitation. In February, EPA began analyzing the impacts of alternative emission limits on local high-sulfur coal reserves. To account for actual and perceived efficiencies of scrubbers, the staff assumed three levels of scrubber control—85 percent, 90 percent, and 95 percent. In addition, two levels of physical coal cleaning were reflected. The first level was crushing to 1.5 inch top-size and the second was crushing to ⅜ inch top-size, both followed by wet beneficiation. In addition, by using seam-by-seam data on coal reserves and their sulfur reduction potential (developed for EPA's Office of Research and Development) it was possible to estimate the sulfur content of the final product coal based on reported chemical properties of coals in the reserve base (OAQPS–78–1, IV–E–12). Since this approach did not require the staff to assume a single level of sulfur reduction for all coal preparation plants, it introduced a major refinement to the analysis previously performed by EPA's consultant. The analysis was substantially completed in March 1979 (OAQPS–78–1, IV–B–57 and IV–B–72).

The April 5, 1979, meeting was called to discuss coal reserve data and the degree of sulfur removal achievable with physical coal cleaning (OAQPS–78–1, IV–E–10). The meeting gave EPA the opportunity to present the results of its analysis and to verify the data and assumptions used with those persons who are most knowledgeable on coal production and coal preparation. EPA sought broad representation at the meeting. Invitees including not only the National Coal Association but representatives from the Environmental Defense Fund, Natural Resources Defense Council, Sierra Club, Utility Air Regulatory Group, United Mine Workers of America, and other interested parties. The invitees were furnished copies of the materials presented at the meeting, subsequent correspondence from the National Coal Association, and minutes of the meeting.

The meeting served to confirm that the coal reserve and preparation data developed independently by the EPA staff were in close agreement with those prepared by the National Coal Association (NCA). In addition, the discussion led EPA to conclude that coal preparation technology which required crushing to ⅜-inch top-size would be unduly expensive, lead to unacceptable energy losses, and pose coal handling problems (OAQPS–78–1, IV–E–11). As a result, the Administrator revised his assessment of state-of-art coal cleaning technology (44 FR 33596, left column).

In an April 19, 1979, letter to the Administrator (OAQPS–78–1, IV–D–763), attorneys for the Environmental Defense Fund and the Natural Resources Defense Council submitted comments on the information presented by the National Coal Association at the April 5, 1979, meeting and in a subsequent NCA letter to the Administrator dated April 6, 1979. In their comments, they were critical of the National Coal Association's assumptions concerning scrubber performance and the removal efficiencies of coal preparation plants. They also noted that the Associaton's data was based on a small survey of the total coal reserves in the Midwest and Northern Appalachia. They argued further that coal blending could serve to reduce the adverse impact on high-sulfur coal caused by a lower emission limit. In doing so, they recognized that the application of coal blending would have to be undertaken on a case-by-case basis. Finally, they maintained that there is no evidence that the coal industry would be unable to meet increases in coal demand even if the National Coal Association's reserve data on coal preclusions were accepted In conclusion, they noted that the Association's data was of questionable relevance since it was predicated on a maximum removal efficiency of 90 percent.

Subsequent correspondence from the National Coal Association served to reaffirm a point that had been made earlier in the rulemaking. That is, utilities would have a choice of either buying lower-sulfur coal and scrubbing to meet the percent removal requirement or buying higher-sulfur coal and scrubbing more than required by the standard in order to meet the emission limitation. In addition, they cited the conservative nature of utilities and stressed that this would be reflected in their coal buying practices. As was discussed at the public hearing and in the written comments such behavior by utilities would result in adverse impacts on the use of certain local high-sulfur coals.

In reaching final conclusions about the impact of the SO_2 standard on coal production, the Administrator judged that utilities would be inclined to select coals that would meet the emission limit with no more than 90 percent reduction in potential SO_2 emissions [1] (44 FR 33596, left column). With this assumption, the analysis revealed that an emission limit of less than 520 ng/J (1.20 lb/million Btu) heat input would create a disincentive to burn a significant portion of the coal reserves in the Midwest and Northern Appalachia (OAQPS–78–1, IV–B–72). If the emission limit had been set at 430 ng/J (1.0 lb/million Btu) heat input, 15 percent of the total reserve base in the Eastern Midwest (Illinois, Indiana, and Western Kentucky) would have been impacted. The impact in Northern Appalachia would be 6 percent and this impact would have been concentrated in the areas of Ohio and the northern part of West Virginia. If only currently

[1] The previous version of the EPA analysis had assumed either 85 or 90 percent control levels in addition to coal washing That approach disregarded the fact that the net reduction in potential SO_2 emissions may have been greater than 90 percent in some cases

owned coal reserves are considered, up to 19 percent of the high-sulfur coals in some regions would be impacted (OAQPS–78–1, IV–B–72). The Administrator judged that such impacts are unacceptable.

The final point made by NCA was that utility coal buying practice typically incorporates a margin of safety to ensure compliance with SO_2 emission limitations. Rather than purchasing a high-sulfur coal that would barely comply with the emission limit, the prudent utility would adopt a more conservative approach and purchase coal that would meet the emission limit with a margin of safety in order to account for uncertainty in coal sulfur variability. This approach, which reflects sound engineering principles, could result in the dislocation of some high-sulfur coal reserves.

The Administrator determined that consideration of a margin of safety in coal buying practice was reasonable. Using NCA's recommendation of an 8.5 percent margin (reported as "about 10 percent" in the preamble to promulgation), coal impacts were reanalyzed. This study showed additional coal market dislocations (OAQPS–78–1, IV–B–72). For example, in Illinois, Indiana, and Western Kentucky, the impact on coal reserves by a 430 ng/J (1.0 lb/million Btu) heat input emission limit increased from 15 percent without the margin to 22 percent when the margin was assumed. Considering only currently owned reserves, the impact increased from 19 percent to 30 percent. Even with the margin, the analysis predicted no significant impact for a 520 ng/J (1.2 lb/million Btu) heat input standard.

Having determined the extent of the potential coal impacts associated with a lower emission limit, the Agency then assessed the potential environmental benefits. The assessment revealed that by 1995 an emission limit of 430 ng/J (1.0 lb/million Btu) heat input would reduce national emissions by only 50 thousand tons per year relative to the 520 ng/J (1.2 lb/million Btu) heat input limit. That is, the projected emissions from new plants would be reduced from 3.10 million tons to a 3.05 million tons as a result of the more stringent emission limit (OAQPS–78–1, IV–B–75).

The petitions providing no information to either refute the assumptions or the findings of the final coal impact analysis. The Sierra Club argued that EPA had misinterpreted its own analysis of coal impacts (Sierra Club petition, page 9). They maintained that the EPA figures presented at the April 5 meeting (OAQPS–78–1, IV–E–11, attachment 3) supported establishment of a 340 ng/J (0.8 lb/million Btu) heat input standard. In doing so the Sierra Club ignored the analysis performed by the Agency after the April 5 meeting, particularly with respect to the Administrator finding that utilities would purchase coal which would meet the emission limit (with margin) with no more than 90 percent reduction in potential SO_2 emissions.

In conclusion, the decision as to the appropriate level of emission limitation rested squarely on two factors. First, the Administrator's finding that a 90 percent reduction in potential SO_2 emissions, measured as a 30-day rolling average, represented the emission reduction achievable through the use of the best demonstrated system of emission reduction, and second, that the marginal environmental benefit of a 430 ng/J (1.0 lb/million Btu) heat input standard coupled with a 90 percent reduction in potential SO_2 emissions could not be justified in light of the potential impacts on high-sulfur coal reserves. If he had determined, as some petitioners suggested, that higher removal efficiencies were achievable on high-sulfur coals, the emission limitation could have been established at a lower level without significant impacts on local high-sulfur coal reserves.

Environmental Defense Fund Procedural Issues

EDF's petition objected to the fact that after the close of the public comment period, representatives of the National Coal Association and a number of members of Congress talked to EPA officials and submitted documents to EPA arguing that the ceiling should be set at 520 ng/J (1.2. lbs/million Btu) heat input. EDF objected to these communications on a number of grounds. First, they argued that it was improper, under Section 307(d) of the Act, for the Agency to consider information submitted more than 30 days after the public hearing. Second, they objected that the Agency failed to make transcripts of the oral communications, and that, in any event, the summaries of those communications that the Agency placed in the docket were inadequate. Third, they implied that Agency officials received additional oral communications which were not documented in the rulemaking docket. Fourth, they objected that these written and oral communications were *ex parte* and therefore improper, citing, for example, *United States Lines, Inc.* v. *FMC*, 584 F. 2d 519 (D.C. Cir., 1978). Fifth, they argued that the Administrator's decision on the ceiling was based in part on information obtained in *ex parte* discussions and thus not placed in the docket as of the date of promulgation, in violation of Section 307(d). Finally, they argued that the communications from members of Congress constituted improper pressure on the Administrator's decision, citing, for example, *D.C. Federation of Civic Associations* v. *Volpe*, 459 F. 2d 1231 (D.C. Cir. 1972). EDF argued that these alleged procedural errors were of central relevance to the outcome of the rule, and that the Agency should therefore convene a proceeding to reconsider.

The Administrator does not believe that the procedures cited by EDF were improper. Moreover, as discussed below, any arguable errors were not of central relevance to the outcome of the rule, and therefore do not constitute grounds for granting EDF's petition to reconsider.

First, it was not improper for the Administrator to consider information submitted more than 30 days after the public hearing. Section 307(d)(5) requires that the Administrator consider documents submitted up to 30 days after the hearing. It does not forbid the Administrator to consider additional comments submitted after that 30-day period.

Second, the Agency's summaries of oral communications were adequate. Section 307(d)(5) does not require, as EDF argues, that Agency officials keep transcripts of their oral discussions with persons outside the Agency. It simply requires the Agency to make a transcript of the public hearing on a proposed rulemaking. Third, Agency officials wrote memoranda of all significant oral communcations between Agency officials and persons outside the executive branch, such as the two meetings with Senator Byrd, and the memoranda were promptly placed in the rulemaking docket. These memoranda accurately reflect the information and arguments communicated to the Agency.

Fourth, the oral and written communications cited by EDF were not *ex parte*. The Agency promptly placed the written comments in the rulemaking docket where they were available to the public. Also, the NCA sent copies of its written comments directly to the principal parties to the rulemaking, including EDF and NRDC. Similarly, the Agency placed the memoranda of oral communcations in the docket where they were available to the public. Any member of the public has had the opportunity to submit a petition for reconsideration if that information was used erroneously by EPA in setting the standard, and several persons have done so.

Fifth, contrary to EDF's assertion, the Administrator's decision on the

emission ceiling was not based on any information not in the docket.

Finally, it was not improper for the Administrator to listen to and consider the views of Senators and Congressmen, including Senator Byrd. It is not unusual for members of Congress to express their views on the merits of Agency rulemaking, and it is entirely proper for the Administrator to consider those views.

EDF objects particularly to a meeting the Administrator attended with Senator Byrd on April 26, 1979, arguing that the contact was *ex parte* and improperly influenced the Administrator's decision. Neither contention is correct. A memorandum summarizing the discussion at the meeting was placed in the docket, and members of the public have had the opportunity to comment on it, as EDF has done. No new information was presented to the Administrator at the meeting.

Senator Byrd's comments at this meeting also did not improperly influence the Administrator. Although the Senator strongly urged the Administrator to set the emission ceiling at a level that would not preclude the use of any significant coal reserves, the Administrator had already concluded from the 1977 Amendments to the Clean Air Act that the revised standards should not preclude significant reserves. This view was based on the Administrator's interpretation of the legislative intent of the 1977 Amendments and was reflected in the proposed emission ceiling of 520 ng/J (1.2 lbs/million Btu) heat input, as discussed in the preamble to the proposed standards (43 FR 42160).

This view was reaffirmed in the final rulemaking, based on the intent of the 1977 Amendments (44 FR 33595–33596). Although the Administrator was aware (as he would have been even in the absence of a meeting) of Senator Byrd's concern that a ceiling lower then 520 ng/J (1.2 lbs/million Btu) heat input would inappropriately preclude significant coal reserves, the Administrator's decision was not based on Senator Byrd's expression of concern. The Administrator had already concluded that anything more than a minimal preclusion of the use of particular coal reserves would, in the absence of significant resulting emission reductions, be inconsistent with the intent of the 1977 Amendments. Because the Agency's analysis showed that even an emission limit of 430 ng/J (1.0 lbs/million Btu) heat input could preclude the use of up to 22 percent of certain coal reserves without significantly reducing overall emissions, the Administrator's judgment was that a ceiling lower than 520 ng/J (1.2 lbs/million Btu) heat input was not justified. Thus, the views of Senator Byrd and other members of Congress, at most, served to reinforce the Administrator's own judgment that the proper level for the standard was 520 ng/J (1.2 lbs/million Btu) heat input. Even assuming therefore, that it was improper for the Administrator to consider the views of members of Congress, this procedural "error" was not of central relevance to the outcome of the rule.

II. SO_2 Minimum Control Level (70 Percent Reduction of Potential Emissions)

The Kansas City Power and Light Company (KCPL), Sierra Club, and Utility Air Regulatory Group (UARG) requested that a proceeding be convened to reconsider the 70 percent minimum control level which is applicable when burning low-sulfur coals. Both the Sierra Club and UARG maintained that they did not have an opportunity to fully comment on either the final regulatory analysis or dry SO_2 scrubbing technology since the phase 3 macroeconomic analysis of the standard (44 FR 33603, left column) and supporting data were entered into the record after the close of the public comment period. Both claimed that their evaluation of this additional information provided insights which are of central relevance to the Administrator's final decision and that reconsideration of the standard is warranted. The KCPL petition did not allege improper administrative procedures, but asked for reconsideration based on their evaluation of the merits of the standard.

In seeking a more stringent minimum reduction requirement, the Sierra Club contended that dry SO_2 scrubbing is not a demonstrated technology and, therefore, no basis exists for a variable control standard. Alternatively, the Sierra Club maintained that if dry technology is considered demonstrated the record supports a more stringent minimum control level. With respect to the regulatory analysis, the petition charged that faulty analytical methodology and assumptions led the Agency to erroneous conclusions about the impacts of the promulgated standard relative to the more stringent uniform or full control alternative. They suggested that analysis performed using proper assumptions would support adoption of a uniform standard.

In support of a less stringent minimum reduction requirement, the UARG petition presented a regulatory analysis which was prepared by their consultant, National Economic Research Associates (NERA). Based on this study, UARG argued that a 50 percent minimum requirement would be superior in terms of emissions, costs, and energy impacts. Finally, they argued that a lower percent reduction would provide greater opportunity to develop dry SO_2 scrubbing technology.

In their petition KCPL sought either an elimination of the percent reduction requirement when emissions are 520 ng/J (1.2 lb/million Btu) heat input or less, or, as an alternative, a reduction in the 70 percent requirement. In support of their request, KCPL set forth several arguments. First, they cited the economic and energy impacts associated with the application of scrubbing technology on low sulfur coals Second, they noted that a significant portion of sulfur in the coal they plan to burn will be removed in the fly ash. Finally, they asserted that health and welfare considerations do not warrant scrubbing of low sulfur coals since their uncontrolled SO_2 emissions are less than the emissions allowed by the standard for high-sulfur coals with 90 percent scrubbing.

The primary basis for the UARG and Sierra Club requests for reconsideration of the minimum control level was the Agency's phase 3 economic modeling analysis (44 FR 33602). Because the phase 3 analysis was completed after the close of the public comment period, it is important that the results of that study are viewed in proper perspective to their role in the Administrator's decision. The petitioners implied that the adoption of the 70 percent variable control standard was based solely on the phase 3 analysis and that the phase 3 analysis was a new venture by the Agency, and therefore, the public was excluded from active participation in the decision process. This notion is false.

Contrary to views of the UARG and the Sierra Club, the phase 3 study did not mark a significant departure from the Agency's earlier analysis of the issue of uniform versus variable control. No new economic modeling concepts were introduced nor were any modeling input assumptions changed from those presented in the phase 2 analysis. Instead, the phase 3 study served merely (a) to refine the analysis by incorporating consideration of dry SO_2 scrubbing in response to public comments and (b) to facilitate specification of the final standard. In effect, phase 3 brought together the results of an analysis that had proceeded under close public scrutiny for more than a year. In order to consider the full range of applicability of dry SO_2 scrubbing systems, it was necessary to introduce a new alternative standard—the variable control standard

with a 70 percent minimum control level. Introduction of this option was considered appropriate since it raised the same kind of economic, legal, and technical policy issues as the earlier analyses of 33, 50, and 90 percent minimum control options.

Within this context, many of the objections to the economic modeling are inappropriate grounds under section 307(d)(7)(B) for reconsideration since they do not involve information on which it was impracticable to comment during the public comment period. For example, the Sierra Club's comments regarding modeling assumptions merely restated those that had been incorporated by reference into their January 1979 comments (OAQPS–78–1, IV–D–631 and IV–D–626). The only new modeling issue raised during phase 3 was the application and cost of dry SO_2 scrubbing. These problems notwithstanding each of the issues raised by the various petitions were evaluated carefully and are discussed below.

Dry Scrubbing Technology

The Sierra Club and UARG both raised issues concerning dry SO_2 scrubbing technology in their petitions for reconsideration. While UARG concurred with EPA's basic approach with respect to dry scrubbing, they maintained that the Agency's objective of developing the full potential of this technology would be better served by a 50 percent minimum reduction requirement. On the other hand, the Sierra Club was most critical of EPA's consideration of dry scrubbing in the rulemaking. They maintained that the public was not afforded sufficient opportunity to comment on dry scrubbing technology. They argued that EPA had not identified dry scrubbing as a demonstrated technology nor had the Agency set forth any regulatory options that embraced the technology. They also asserted that the treatment of dry scrubbing in the rulemaking was inconsistent with Agency actions concerning other emerging technologies such as the establishment of commercial demonstration permits for solvent refined coal and fluidized bed combustion, and the rejection of catalytic ammonia injection for NO_x control on the grounds that it had not been employed on a full-scale facility. They also maintained that EPA had shown little interest in dry scrubbing prior to the spring of 1979 and seized upon it only after the need arose to justify a 70 percent minimum reduction requirement. Finally, the Sierra Club asserted that even if one assumed dry scrubbing is adequately demonstrated, the 70 percent reduction requirement is too low. In doing so, they cited information (Sierra Club petition, page 8) in the record that indicated that "up to 90 percent reduction" can be achieved with such systems.

A review of the public record belies these charges. The preamble to the proposed standards identified dry SO_2 scrubbing, including spray drying, as an alternative to wet FGD systems (43 FR 42160, left column). Subsequently, a number of individuals and organizations either submitted written comment or presented testimony at the public hearing in support of a variable control standard since it would not foreclose the development of dry SO_2 control technology. For example, the spokesman for the Public Service Company of Colorado (PSCC) testified that his firm was actively pursuing dry SO_2 control technology (dry injection of sodium-based reagents upstream of a baghouse) because it offered a number of advantages compared to wet technology. Advantages included lower energy consumption, fewer maintenance problems, and simplified waste disposal (public hearing transcript, December 13, 1978, pages 92–94). When questioned by the hearing panel, PSCC testified that 70 percent removal is achievable with dry scrubbing and that they would pursue the technology if a 70 percent requirement was adopted (public hearing transcript, December 13, 1978, page 102). Similarly, Northern States Power testified that adoption of a sliding scale would give impetus to their examination of dry SO_2 control systems which employ a spray absorber and a fabric filter (public hearing transcript, December 13, 1978, page 226). Finally, the Department of Public Utilities, City of Colorado Springs testified that they have a program to conduct on-site pilot tests of a spray-drying system for SO_2 control. It was also noted that if a sliding scale approach was adopted "we feel there is no question but that dry techniques would be used" (public hearing transcript, December 13, 1978, pages 266–267).

The Air Pollution Control Commission, Colorado Department of Health urged in their written comments that the proposed emission floor be raised to 172 ng/J (0.40 lb/million Btu) heat input in order to permit the development and application of dry control techniques such as the injection of dry absorbants into a baghouse. They noted that their recommendation would require approximately 65 percent reduction on a typical western low-sulfur coal (OAQPS–78–1, IV–D–212). The Washington Public Power Supply System also submitted written comments that affirmed the Agency's finding on dry scrubbers as set forth in the proposal. They indicated that dry scrubbing was superior to wet technology when applied to western low-sulfur coal. They noted that the application of dry scrubbers would result in lower capital, fuel, and operation and maintenance costs, as well as lower water use and simplified waste disposal. They indicated further that the uncertainty of being able to achieve the proposed 85 percent reduction requirement would foreclose the installation of dry scrubbing technology. Therefore, they recommended that the proposed emission floor be raised to at least 210 ng/J (0.5 lb/million Btu) heat input (OAQPS–78–1, IV–D–330).

Because of these comments and the public hearing testimony, the Agency carried out additional investigations of dry scrubbing technology during the post-comment period. The findings of the analysis (44 FR 33582 and EPA 450/3–79–021, page 3–61) confirmed the views of the commenters that the adoption of a uniform percentage reduction requirement would have constrained the development of dry scrubbing technology. After carefully reviewing the available pilot plant data and information on the three full-scale units that are under construction, it was the Administrator's judgment that the technology employing spray dryers could achieve 70 percent reduction in potential SO_2 emissions on both low-sulfur alkaline and nonalkaline coals. Data on higher emission reduction levels such as those noted by the Sierra Club were discounted since they reflected short-term removal efficiencies (not representative of longer periods of performance) and they were achieved when high-alkaline content coals were fired. The Administrator's judgment was also tempered in this regard by the public comments which indicated that removal requirements higher than 70 percent would discourage the continued development of the technology. Similarly, these same commenters clearly indicated that the technology was capable of exceeding the 50 percent reduction requirement suggested by the Utility Air Regulatory Group.

The Sierra Club commented that EPA was inconsistent in its treatment of dry scrubbing and catalytic ammonia injection. In rejecting catalytic ammonia injection for NO_x control, the Administrator noted that it had not been adequately demonstrated. A review of the record reveals that the primary proponent of this technology, the State

of California Air Resources Board, also recognized that it was not sufficiently advanced at this time to be considered. Instead, they merely recommended that the standard require plants to set aside space so that catalytic ammonia injection could be added at some future date (OAQPS-78-1, IV-D-268). In comparison, dry scrubbing has undergone extensive testing at pilot plants, and there are three full-scale facilities under construction that will begin operation in the 1981-82 period.

With respect to commercial demonstration permits for solvent refined coal and fluidized bed combustion, the standard merely allows initial, full-scale demonstration units some flexibility. Subsequent commercial facilities will be required to meet the final standards. In adopting this provision, the Administrator recognized that initial full-scale demonstration units often do not perform to design specification, and therefore some flexibility was required if these capital intensive, front-end technologies were to be pursued. On the other hand, the Agency concluded that more conventional devices such as dry scrubbers could be scaled up to commercial-sized facilities with reasonable assurance that the initial facilities would comply with the applicable requirements. In view of this, the inclusion of dry scrubbing under the commercial demonstration permit provision was not appropriate.

Finally, in a letter dated September 17 1979, to the Administrator, the Sierra Club submitted additional information to buttress its argument that dry scrubbing is not demonstrated technology. This letter cited EPA's "FGD quarterly Report" of Spring 1979. The report indicates that the direct injection of dry absorbents (such as nahcolite) into the gas stream may be a breakthrough, yet it calls for further pilot plant studies. The inference the Sierra Club drew from the article was that the EPA technical staff does not believe dry scrubbing is sufficiently developed to be considered in the rulemaking. The Sierra Club failed to recognize that there are several different dry scrubbing approaches in different stages of development. The "FGD Quarterly Report" does not pertain to the approach employing a spray dryer and baghouse with lime absorbent which serves as the basis for the Administrator's finding (EPA-450/3-70-021 at 3-61).

The Sierra Club also cited an article in the Summer 1979 "FGD Quarterly Report" on vendors' perspectives toward dry scrubbing. In doing so, the Sierra Club noted that the article indicates that vendors expressed an attitude of caution toward dry scrubbing which led the Sierra Club to conclude that the technology is not available. It should be noted from the article that only one of the vendors present was actively engaged in dry scrubbing and that firm was quite positive in their remarks. Babcock and Wilcox, who had conducted spray dryer pilot plant studies and is pursuing contracts for full-scale installations, commented that "while the dry scrubbing approach is new, the technology is proven."

Economic Modeling

The Agency's regulatory analysis concluded that the variable control standard with a 70 percent minimum control level would result in equal or lower national sulfur dioxide emissions than the uniform 90 percent standard while having less impact on costs, waste disposal, and oil consumption (44 FR 33607, middle column and 33608). The Sierra Club petition charged that the Agency used an unrealistic model and faulty assumptions in reaching these conclusions. The petition alleged that utility behavior as predicted by the EPA model is "incredible" and that this incredible behavior leads to "the outlandish notion that stricter emission controls will lead to more emissions." The Administrator finds this allegation to be without merit.

The principle modeling concept being challenged is whether or not increased costs of constructing and operating a new plant (due to increased pollution control costs) will affect the utility operator's decisions on boiler retirement schedules, the dispatching of plants to meet electrical demand, and the rate of construction of new plants. The model used for the analysis assumed that utility companies over the long term will make decisions that minimize the cost of electricity generation. That is, (1) under any demand situation utilities will first operate their equipment with the lowest operating costs, and (2) existing generating capacity will be replaced only if its operating costs exceed the capital and operating costs of new equipment. While political, financial, or institutional constraints may bar cost-minimizing behavior in individual cases, the Administrator continues to believe that the assumption of such behavior is the most sound method of analyzing the impacts of alternative standards.

Under this approach, the model simultaneously adjusts both the utilization of existing plants and the construction schedule of new plants (subject to Subpart Da) based on the relative economics of generating electricity under alternative standards. Hence, average capacity factors for the population of new plants may vary among standards due to variations in the mix of base and intermediate loaded plants which are brought on line in any one year. But this does not mean, as concluded in the Sierra Club petition at page 8, that the model predicted that utilities would permit new base-loaded units to remain idle while they continue to build still more new units.

The petition also alleged that this modeling concept was introduced in the phase 3 analysis, which was completed after the close of the public comment period, and hence the modeling rationale was not subject to public review. The petition went on to criticize some of the assumptions in the model charging that they were not even mentioned in the record.

The Administrator finds no basis for the Sierra Club's assertion that the modeling methodology and input assumptions were not exposed for public review. First, the same model was used for the phase 1, 2, and 3 analyses. The basic model logic was explained in the preamble to the September proposal and comments were solicited specifically on the use of a cost optimization model for simulating utility decisions (43 FR 42162, left column).

Secondly, the model's input assumptions were subjected to broad review. Assumptions were presented in the September preamble and in even greater detail in the consultant's reports which are part of the record (OAQPS-78-1, II-A-42, II-A-90, and II-A-91) Following proposal, the Agency convened an interagency working group to review the macroeconomic model and the Agency's input assumptions (44 FR 33604, left column). Members of the group represented a spectrum of expertise and interests (energy, employment, environment, inflation, commerce). The group met numerous times over a period of two months, including meetings with UARG, NRDC, and Sierra Club. As a result of the group's recommendations, the phase 2 analysis was conducted. A full description of the analysis including changes to the modeling assumptions was presented at the public hearing and a detailed report was put into the record (OAQPS-78-1, IV-A-5). For the phase 3 analysis accompanying promulgation, the only change in modeling assumptions from phase 2 was the introduction of dry scrubbing technology. Based on the detailed record established, the Administrator concludes that the Sierra Club had ample opportunity to analyze and

comment on the Agency's analytical approach and did so by incorporating the EDF and NRDC comments into their January 1979 comments (OAQPS–78–1, IV–D–626).

The Sierra Club also criticized the conclusions of the Agency's regulatory analysis because the assumed oil prices were too low and the nuclear plant growth rate was too high. To assist in evaluating the petitions, two sensitivity tests were performed on the Agency's regulatory analysis. Using the phase 3 assumptions as a base, the analysis was rerun first assuming higher oil prices and then assuming both higher oil prices and a lower nuclear growth rate (OAQPS–78–1, VI–B–16). The studies addressed the promulgated standard, the full control option (uniform 90 percent control), and a variable control standard with a 50 percent minimum control requirement as recommended by UARG. The predictions for 1995 are summarized in Tables 2 and 3, respectively. For comparison, the phase 3 results are repeated in Table 1.

With respect to energy input assumptions, the oil prices used by the Agency for the phase 3 analysis were based on the Department of Energy's estimate of future crude oil prices. These estimates are now probably low because of the 1979 OPEC price increase which occurred after promulgation of the standard. For the sensitivity analysis, the following oil prices in 1979 dollars were assumed:

Assumed Oil Prices

[Dollars per Barrel]

	Sensitivity analysis	Phase 3
1985	25	16
1990	30	20
1995	38	26

These prices were obtained from conversations with DOE's policy analysis staff. The prices may appear low in comparison to the example of $41.00 per barrel spot market oil given in the Sierra Club petition, but the Sierra Club figure is misleading because utilities seldom purchase spot market oil. The meaningful parameter is the average refiners' acquisition cost, which was $21/barrel at the time of this analysis. The original nuclear capacity assumptions were based on the industry's announced plans for new capacity. For sensitivity testing, these estimates were modified by excluding nuclear power plants in the early planning stages while retaining those now under construction or for which, based on permit status, plans appear firm. The following assumptions of total nuclear capacity resulted:

Table 1.—*Summary of 1995 Impacts With Phase 3 Assumptions* [1]

	Level of control with 520 ng/J maximum emission limit			
	Current standards	Variable control, 50 pct minimum	Variable control, 70 pct minimum	Full control
National SO_2 Emissions (million tons)	23 8	20 6	20 5	20 7
East [2]	11 2	9 7	9 7	10 1
Midwest	8 3	8 0	8 0	7 9
West South Central	2 6	1 8	1 7	1 7
West	1 7	1 1	1 1	0 9
Incremental Annualized Cost (billions 1978 $)	2 9	3 3	4 4
Incremental Cost of SO_2 Reduction (1978 $/ton)	914	1,036	1,428
Oil Consumption (million bbl/day)	1 4	1 6	1 6	1 8
Coal Production (million tons)	1,767	1,745	1,752	1,761
Total Coal Capacity (GW)	554	537	537	520

[1] With wet and dry scrubbing and the following energy assumptions

	Oil prices ($ 1975)	Nuclear Capacity (GW)
Year		
1985	$12.90	97
1990	16 40	165
1995	21 00	228

[2] See 44 FR 33608 for designation of census regions

Table 2.—*Summary of 1995 Impacts With Higher Oil Prices* [1]

	Level of control with 520 ng/J maximum emission limit			
	Current standards	Variable control, 50 pct minimum	Variable control, 70 pct minimum	Full control
National SO_2 Emissions (million tons)	23.2	19.8	19.6	19.7
East [2]	10.9	9.1	9.1	9.5
Midwest	8.2	7.9	7.8	7.8
West South Central	2.6	1.7	1.6	1.5
West	1.6	1.1	1.0	0.9
Incremental Annualized Cost (billions 1978 $)		3.3	3.6	5.0
Incremental Cost of SO_2 Reduction (1978 $/ton)		967	977	1,049
Oil Consumption (million bbl/day)	0.9	0.9	0.9	0.9
Coal Production (million tons)	1,800	1,797	1,802	1,832
Total Coal Capacity (GW)	588	587	587	587

[1] With wet and dry scrubbing and the following energy assumptions

	Oil prices ($ 1975)	Nuclear capacity (GW)
Year		
1985	$20.20	97
1990	24.20	165
1995	30.70	228

[2] See 44 FR 33608 for designation of census regions

Table 3.—*Summary of 1995 Impacts With Higher Oil Prices and Less Nuclear Growth* [1]

	Level of control with 520 ng/J maximum emission limit			
	Current standards	Variable control, 50 pct minimum	Variable control, 70 pct minimum	Full control
National SO_2 Emissions (million tons)	25.0	20.9	20.6	20.5
East [2]	12.0	9.8	9.7	10.1
Midwest	8.6	8.2	8.1	8.0
West South Central	8.6	1.8	1.7	1.6
West	1.7	1.2	1.1	0.9
Incremental Annualized Cost (billions 1978 $)		3.8	4.1	5.9
Incremental Cost of SO_2 Reduction (1978 $/ton)		883	914	1,259
Oil Consumption (million bbl/day)	0.9	0.9	0.9	0.9
Coal Production (million tons)	1,940	1,943	1,946	1,984
Total Coal Capacity (GW)	644	644	644	643

[1] With wet and dry scrubbing and the following energy assumptions

	Oil prices ($ 1975)	Nuclear Capacity (GW)
Year.		
1985	$20.20	92
1990	24.20	141
1995	30.70	173

[2] See 44 FR 33608 for designation of census regions

Assumed Nuclear Capacity

	Sensitivity analysis	Phase 3
1985	92 GW	97 GW
1990	141 GW	165 GW
1995	173 GW	228 GW

Environmentally, the impact of higher oil prices was to reduce SO_2 emissions (Table 2). For example, under the promulgated standard (hereafter referred to as "the standard") national SO_2 emissions in 1995 were projected to drop from 20.5 million tons predicted in phase 3 (44 FR 33608) to 19.6 million tons. This reduction occurred because the higher oil prices led to the retirement of about 50 gigawatts (GW) of existing oil-fired capacity. While these retirements increased the demand for new coal-fired plants, new plants (subject to Subpart Da) on average were less polluting than the oil-fired capacity they replaced. Therefore, the net effect of oil replacement on a broad regional basis was to reduce SO_2 emissions.

The relative impacts of the alternative standards under the sensitivity tests remained about the same. Sulfur dioxide emissions under the standard were still predicted to be lower than with either full control or the 50 percent variable standard. The emissions benefit relative to full control was reduced from 200,000 tons per year to 100,000 tons per year. Regionally, the effect of the higher oil prices on the relative impacts of the standards was mixed. In comparison to full control, the standard continued to reduce emissions in the East by 400,000 tons per year, but resulted in an additional 70,000 tons in the West and 100,000 tons in the West South Central (relative to phase 3). However, as pointed out above, emissions in all regions were less than or equal to those under the phase 3 oil price assumptions.

The cost of all the standards increased under the higher oil price assumption. This increase was due to the cost of additional coal capacity and corresponding emission control equipment. Relative to the standard, the cost of full control increased by $300 million per year over the $1.1 billion difference predicted under lower oil prices.

At the higher oil prices, 1995 oil consumption by utilities was predicted to be the same under all standards tested. Depending on the standard, consumption was 500,000 to 800,000 barrels per day lower than under the phase 3 projections with lower prices. The reason that the environmental standards had no effect on oil consumption was that at the assumed rate of oil price increase, all base- and intermediate-loaded oil capacity was retired by 1995 and the only remaining oil use was in combustion turbines used to meet peak demand.

Under the assumption of both high oil prices and slowed nuclear growth (Table 3), national and regional SO_2 emissions were predicted to be about the same as under the phase 3 projections. This effect was due to the counterbalancing emission impacts. As noted above, higher oil prices resulted in a net decrease in SO_2 emissions. But at the same time the reduced supply of nuclear generation capacity precipitated demand for an additional 55 GW of new coal capacity beyond that required under the projection with high oil prices. On a national level the emissions from these new coal-fired plants offset the emission reductions achieved by the oil replacements.

With this additional 55 GW of new coal-fired capacity, the environmental impact of alternative standards was more significant. Baseline emission projections (i.e., assuming no change to the original standard) increased from 23.8 million tons per year under the phase 3 energy assumptions to 25.0 million tons per year. Accordingly, the promulgated standard reduced national SO_2 emissions in 1995 by almost 4.5

million tons per year in contrast to about 3.5 million tons per year under both the phase 3 and the high oil price sensitivity projections.

While emission levels were roughly the same as under the phase 3 energy assumptions, the relative impacts of the alternative standards changed somewhat. National emissions were predicted to be 100,000 tons less under full control than under the standard. Relative to full control, the standard was still predicted to reduce emissions by about 400,000 tons in the East, but on a national basis this was offset by emission increases in the other regions. With higher oil prices and less nuclear capacity, the environmental benefit of full control in the West and West South Central was greater by about 100,000 tons, but this impact is masked in Table 3 due to rounding. The variable standard with a 50 percent minimum control level resulted in about 400,000 tons per year more emissions than full control and about 300,000 tons per year more than the standard.

The total cost of all the alternatives increased due to the increased coal capacity. Relative to the standard, the cost of the 50 percent variable control standard remained about the same. The full control standard, however, was significantly more expensive. The marginal cost of full control (relative to the standard) increased from $1.1 billion under the phase 3 energy assumptions to $1.8 billion.

Energy impacts were about the same as those predicted in the high oil price sensitivity runs. Oil consumption was still predicted at about 900 000 barrels per day under all alternative standards. Coal production under all alternatives increased by about 100 million tons per year.

Even considering the uncertainty of future oil prices and nuclear capacity, the Administrator found no basis for convening a proceeding on the modeling issue. The sensitivity runs did not show significant changes in the relative impacts of the alternatives. Under the sensitivity test with both high oil prices and slowed nuclear growth, full control for the first time showed lower emissions nationally than the standard. But the cost of this additional 100,000 tons of control was estimated at $1.8 billion, which represents more than a 40 percent increase in the incremental cost of the standad (Table 3). The principal environmental benefit of full control would be felt in the West and West South Central. Through case-by-case new source review ample authority exists to require more stringent controls as necessary to protect our pristine areas and national parks (44 FR 33584, left column). As a result, the Administrator continues to believe that the flexibility offered by the standard will lead to the best balance of energy, environmental, and economic impacts than either a uniform 90 percent standard or a 50 percent variable standard and hence better satisfies the purposes of the Act.

On the other side of the modeling issue, UARG charged that the Agency's regulatory analysis does not support a 70 percent minimum requirement. The petition called the Agency's control cost estimates unrealistic and presented a macroeconomic analysis which concluded that a 50 percent minimum requirement would result in a more favorable balance of cost, energy, and environmental impacts.

Response to the UARG petition was difficult because the UARG position was presented in two separate reports submitted at different times, and the two reports reached different conclusions. In the formal petition, UARG recommended 50 percent minimum control and promised a detailed report by NERA supporting their position. When the NERA report arrived six weeks later, if recommended 30 percent control. In light of this confusion, it was decided to review each report separately based on its own merits, but devote primary attention to the 50 percent recommendation. After reviewing UARG's macroeconomic analysis, the Administrator finds no convincing arguments for altering the conclusion that the 70 percent minimum removal requirement provides the best balance of impacts. In the formal petition, UARG's conclusion that a 50 percent standard is superior was based on a NERA economic analysis which assumed that only wet scrubbing technology was available to utilities. A detailed analysis of the NERA results was not possible because only summary outputs were supplied in their comments. But the results of this analysis seem to coincide with the Agency's conclusions that there are energy, environmental, and economic benefits, associated with standards that provide a lower cost control alternative for lower sulfur coals. The problem with the UARG initial analysis is that it overlooked the economic benefits of dry scrubbing.

In recognition of this shortcoming, UARG presented their estimate of the costs of dry scrubbing made by Battelle Columbus Laboratories (UARG petition, page 25) and then hypothesized without supporting analysis that "with realistic cost assumptions the advantages of a lower percent removal are likely to increase even further" (UARG petition, page 27). Table 4 compares Battelle's costs to those used in the EPA regulatory analysis. The two estimates are almost the same. More importantly, the two estimates agree that the cost of a 70 percent efficient dry system is not significantly greater than the cost of a 50 percent efficient system, and this conclusion had important implications in the specification of the standard. Based on these comparisons, the Administrator finds that the UARG petition supports the Agency's dry scrubbing cost assumptions and the finding that no significant cost benefit will result from a standard with a 50 percent minimum control level.

Table 4.—*Comparison of UARG and EPA dry SO_2 Scrubbing Costs* [1] *(Mills/kwh)*

Percent removal	Inlet sulfur (lbs SO_2/million Btu)	UARG	EPA
50	0 80	[2] 1 68	2 06
	2 00	[2] 2 13	2 44
70	0 80	1 97	2 66
	2 00	2 54	2 66

[1] Wet scrubbing costs range up to 6 mills/kwh
[2] UARG costs based on 55 percent removal

In their second report, UARG presented additional economic analyses by NERA. In those analyes, the impacts of 30, 50, and 70 percent minimum control standards were tested assuming that both wet and dry scrubbing technology were available. The analyses were performed with three different sets of control cost assumptions—EPA's costs, Battelle's costs, and an additional set of costs specified by NERA. The report concluded that the 70 percent standard is superior using EPA's costs but that under the other cost estimates the 30 percent standard is better. The cost effectiveness of alternative standards (dollars per ton of pollutant removed) was their principal basis of evaluation. UARG then alleged that EPA overestimated the differences in cost between wet and dry scrubbing and that this error led to the wrong conclusion about the impacts of the 70 percent minimum removal requirement. The EPA cost assumptions were criticized primarily because different methods were used to estimate dry and wet scrubbing costs. To justify their position, UARG presented estimates of wet and dry scrubbing costs developed by Battelle. UARG believes that Battelle understand scrubber costs, but that Battelle's relationship between wet and dry scrubbing costs is more accurate than EPA's (UARG petition, page 7). As noted above, Battelle agreed with the Agency's dry scrubbing costs, but for

wet scrubbing the Battelle costs were substantially lower than the Agency's.

Typically, when comparing results of studies, the Agency has detailed documentation with which to compare the methods of costing and analysis. In this case, the Administrator had documentation for neither the NERA costs nor the Battelle costs. The NERA costs were unreferenced and supported by neither engineering analysis nor vendor bids. They assumed that the capital cost of a dry scrubber is 10 percent less than that for a comparable wet scrubber and that the operating costs and energy requirements are the same for the two systems. The UARG petition promised a detailed report from Battelle, but the report was not delivered. Without a basis for evaluation, the Battelle and NERA costs can only be considered as hypothetical data sets for the purpose of sensitivity testing of the economic analysis. They cannot be considered as new information on SO_2 control costs.

The EPA cost estimates, on the other hand, have withstood several critical tests. The PEDCo cost model for wet scrubbers which was used by EPA was thoroughly reviewed by Department of Energy (DOE) consultants, and DOE concurred with the EPA estimates through the interagency working group. Later, the Agency's costs were again reviewed in detail against wet scrubber costs predicted by the Tennessee Valley Authority's scrubber design model. While the two models initially seemed to produce divergent results, careful analysis of the respective costing methodology showed that for similar design specifications the two models produced costs that were very close, the major difference stemming from different assumptions about the construction contingency fee (OAQPS-78-1, IV-B-50). The Administrator concluded from these cost comparisons that the Agency's flue gas desulfurization cost assumptions are reasonable.

The EPA dry scrubbing costs were based primarily on engineering studies submitted by electric utility companies and equipment vendors for the full-scale utility systems now on order or under construction. Using these studies, the EPA cost estimates were made in full cognizance of the basic assumptions used in the PEDCo wet scrubbing model. The result was that for economic modeling purposes (OAQPS-78-1, IV-A-25, page B-17) the dry scrubbing cost estimates in the background document (EPA 450/5-79-021, page 3-67) were increased to reflect similar fuel parameters, local conditions, and degree of design conservatism as reflected in the wet scrubbing costs. Since care was taken in aligning these costs, the Administrator does not accept UARG's allegation that EPA's costs for wet and dry scrubbing are invalid because they were developed on an inconsistent basis.

Even if EPA accepted UARG's unsubstantiated cost assumptions, the NERA sensitivity analyses provided no new insights nor did they materially contradict the Agency's basic conclusions about the standard. Using the Battelle costs and NERA's "alternative scrubber costs" as a range, NERA predicted that relative to 50 percent minimum control, a 70 percent standard would reduce national SO_2 emissions by an additional 250 to 450 thousand tons per year compared to about 100 thousand tons estimated by EPA (Table 1). NERA predicted the additional costs of a 70 percent minimum standard relative to a 50 percent requirement would be between $300 million and $400 million per year compared to $300 million predicted by EPA. It was only in moving to 30 percent control that the NERA results showed a distinct cost savings ($600 to $900 million) over the 70 percent level, but the 30 percent standard produced an additional 700 thousand tons per year of SO_2 under both of their control cost scenarios. The Administrator rejects the 30 percent standard advocated by UARG because the potential cost savings do not justify the potential emission increases. In conclusion, the trade-offs between costs and emissions shown by UARG are generally similar to those predicted by EPA in promulgating the standard and therefore do not support a different standard from the 70 percent variable standard adopted.

Other Issues

Kansas City Power and Light Company sought either an elimination of the percent reduction requirement when emissions are 520 ng/J (1.2 lbs/million Btu) heat input or less or as an alternative a reduction in the 70 percent minimum control requirement. In their arguments, KCPL cited annualized control costs for wet scrubbing of $11.4 million and an energy penalty of 70 thousand tons of coal per year to operate a scrubber. Second, they noted that 14 percent of the potential SO_2 emissions from the coal they plan to burn will be removed by the fly ash. Taking these two factors in account, KCPL computed a cost effectiveness ratio for a hypothetical 650 MW unit to be $3,600 per ton of sulfur removed and concluded that such control was too expensive. Finally, they concluded that scrubbing low-sulfur coals is not warranted since uncontrolled SO_2 emissions from their new plants will be less than the emissions allowed by the standard for high-sulfur coals with 90 percent scrubbing.

After careful review, the Administrator finds that the KCPL petition provided no legal or technical basis for reconsidering the final rule. First, the question of whether a plant burning low-sulfur coal should be required to meet the same percentage reduction requirement as those burning high-sulfur coal has been a central issue throughout this decision-making. Since this issue was raised in the proposal (43 FR 42155, left column), KCPL had ample opportunity to make their points during the public comment period. In fact, it was the recognition of this trade-off in emissions between high-sulfur and low-sulfur coal that led the Administrator to first consider the concept of variable control standards (43 FR 42155, right column). While sulfur removal by fly ash does not represent best demonstrated technology for SO_2 control, sulfur removal by fuel pretreatment, fly ash, and bottom ash may be credited toward meeting the 70 percent requirement.

Second, the KCPL petition does not allege the requisite procedural error that the standard was based on information on which they had no opportunity to comment. Their objections center primarily on the economic and energy impacts of wet SO_2 scrubbing on low-sulfur coal. These issues were clearly identified by the Agency in the background document supporting proposal (OAQPS-78-1, III-B-3, Chapters 5 and 7). Furthermore, the preamble to proposal specifically requested comments on the Agency's assumptions for the regulatory analysis (43 FR 42162, left column).

Finally, and more importantly, the major points made by KCPL are not of central relevance to the outcome of the rule because the information presented does not refute the Agency's data base on wet scrubbing. Consider the following comparisons to the assumptions of the EPA regulatory analysis.

(a) The control costs quoted by KCPL for a 650 MW unit were $31 million in capital and $6.2 million in operating expenses. The EPA assumptions applied to a comparably sized unit result in $55 million in capital costs and $7 million in operating expense.

(b) KCPL quoted an energy impact of 8 tons of coal per hour to operate the scrubber. Considering their operating requirement of 460 tons of coal per hour, the energy penalty of SO_2 control is 1.7

percent. The Agency's economic model assumed 2.2 percent.

(c) KCPL computed cost effectiveness of the standard at $3600 per ton of sulfur removed. This figure is based on a misunderstanding of the application of the fly ash removal credit toward the 70 percent removal requirement. According to the standard, the scrubbing requirement when assuming a 14 percent SO_2 removal in flyash is 65 percent rather than 56 percent as calculated by KCPL. At 65 percent scrubbing, the cost per ton of sulfur removed is $3100. This converts to a cost of $1550 per ton of sulfur dioxide removed which is similar to the costs estimated by EPA for low-sulfur coal applications (OAQPS-78-1, III-B-3 and IV-B-14).

Thus, the Administrator has already concluded that energy and economic costs greater than those cited by KCPL are justified to achieve the emission reductions required by the standard.

Conclusions on Minimum Control Level

After carefully weighing the arguments by the three petitioners, the Administrator can find no new information or insights which are of central relevance to his conclusions about the benefits of a variable control standard with a 70 percent minimum removal requirement. The Sierra Club and UARG correctly point out that the Agency's phase 3 analysis was completed after the close of the public comment period and that they were therefore unable to comment on the final step of the regulatory analysis. But in assessing these comments it is important to put the phase 3 analysis in proper context with its role in the final decision. The Administrator's conclusions about the responses of the utility industry to alternative standards were not based on phase 3 alone, but a series of economic studies spanning more than a year's effort. These analyses were performed under a range of assumptions of economic conditions, regulatory options, and flue gas desulfurization parameters. The phase 3 analysis was merely a fine tuning of the regulatory analysis to reflect dry scrubbing technology.

No new modeling concepts or assumptions were introduced in phase 3. The fundamental modeling concept as introduced in the September proposal (43 FR 42161, right column) has not changed. The model input assumptions were the same as those of the phase 2 analysis presented on December 8, 1978 (44 FR 54834, middle column), and at the December 12 and 13, 1978, public hearing. Detailed consultants' reports on the modeling analyses were available for comment before the close of the public comment period. This public record provided adequate opportunity for the public to comment both on the principal concepts and detailed implementation of the regulatory analysis before the close of the public comment period.

Even though new information was added to the record after the close of the comment period, none of the petitions raised valid objections to this information or cast any uncertainty that is germane to the final decision. The Administrator has very carefully weighed the petitioners comments on dry scrubbing and the UARG sensitivity analysis on pollution control costs. Not only did the UARG analysis generally confirm the conclusions of the EPA regulatory analysis, but it established that even if dry scrubbing costs vary substantially, the relative impacts of a 50 versus 70 percent minimum removal requirement change very little. The 70 percent standard was estimated to produce lower emissions for only slightly higher costs. Differences in cost effectiveness, which UARG seem to weigh most heavily, varied by only $2 to a maximum of $50 per ton of SO_2 removed across alternative cost estimates. In the final analysis none of the petitions repudiated the Agency's findings on the state of development, range of applicability, or costs of dry SO_2 scrubbing. In light of these findings, the Administrator finds the information in the petitions not of central relevance to the final rule and therefore denies the requests to convene a proceeding to reconsider the 70 percent minimum removal requirement.

III. SO_2 Maximum Control Level (90 percent reduction of potential SO_2 emissions)

Petitions for reconsideration submitted by the Utility Air Regulatory Group (UARG) and the Sierra Club questioned the basis for the maximum control level of 90 percent reduction in potential SO_2 emissions, 30-day rolling average. The other petitions did not address this issue. However, in a July 18, 1979, letter, the Environmental Defense Fund (EDF) requested EPA to review utilization of adipic acid scrubbing additives as a basis for a more stringent maximum control level. An additional analysis by UARG was forwarded to EPA on January 28, 1980. Although it was reviewed by EPA, a detailed response could not be prepared in the three days afforded EPA for comment prior to the court's deadline of January 31, 1980, for EPA to respond to the petitions. However, the only issue not previously raised by UARG (boiler load variation) has been addressed by this response.

With their petition, UARG submitted a statistical analysis of flue gas desulfurization (FGD) system test data which purportedly revealed certain flaws in the Agency's conclusions. The UARG petition maintained that a scrubber with a geometric mean (median) efficiency of 92 percent could not achieve the standard because of variations in its performance. UARG also maintained that the highest removal efficiency standard that can be justified by the Agency's data is 85 percent, 30-day rolling average. In the alternative, they suggested that the 90 percent, 30-day rolling average standard could be retained if an adequate number of exemptions were permitted during any given 30-day averaging period. On the other hand, the Sierra Club questioned why the standard had been established at 90 percent when the Agency had documented that well-designed, operated, and maintained scrubbers could achieve a median efficiency of 92 percent. In doing so, they argued that a 90 percent, 30-day rolling average standard was not sufficiently stringent.

After reviewing their petitions, the Administrator finds that the Sierra Club and UARG overlooked several significant factors which were of critical importance to the decision to promulgate a 90 percent, 30-day rolling average standard. The Sierra Club position was based on a misunderstanding of the statistical basis for the standard. The UARG analysis was flawed because it did not consider the sulfur removed by coal washing, coal pulverizers, bottom ash, and fly ash (hereafter, collectively referred to as sulfur reduction credits). Instead the UARG petition based its conclusions on the performance of the FGD system alone. In short, UARG did not analyze the promulgated standard (44 FR 33582, center column). Furthermore, UARG underestimated the minimum performance capability of scrubbers by assuming that future scrubbers would not even achieve the level of process control demonstrated by the best existing systems tested by EPA.

EPA has prepared two reports which re-analyze the same FGD test data considered in UARG's analysis. One report identified the important design and operating differences in the FGD systems tested (OAQPS-78-1, VI-B-14) by EPA and the second report provided additional statistical analyses of these data (OAQPS-78-1, VI-B-13). The results of the EPA analyses showed that:

1. Flue gas desulfurization systems can achieve a 30-day rolling average efficiency between 88 percent and 89

percent (base loaded boilers) or between 86 and 87 percent (peak loaded boilers) with no improvements in currently demonstrated process control.

2. Even if a new FGD system attained only 85 percent efficiency (30-day rolling average), a 90 percent reduction in potential SO_2 emissions can be met when sulfur reduction credits are considered.

To clarify the basis for the Agency's conclusions, the following discussion reviews the development of information used to establish the final percent reduction standard. Initially, EPA studied the application of FGD systems for the control of SO_2 emissions from power plants. As part of that effort, information which described the status and performance of FGD systems in the U.S. and Japan was inventoried and evaluated. These evaluations included the development of design information on how to improve the median efficiency of FGD systems based upon an extensive testing program at the Shawnee facility (OAQPS-78-1, II-A-75). The Shawnee test data and other data (OAQPS-78-1, II-A-71) on existing FGD systems were generated by short-term performance tests. These data did not define the expected performance range (the minimum and maximum SO_2 percent removal) of state-of-the-art FGD systems.

Because a continuous compliance standard was under consideration, information about the process variation of FGD systems was needed to project the performance range of scrubber efficiency around the median percent removal level. For the purpose of measuring process variation, several existing FGD systems were monitored with continuous measurement instrumentation. The selection of FGD systems to be tested was limited principally to the few FGD systems available which were attaining 80 to 90 percent median reduction of high-sulfur coal emissions. When examining the results of these tests, it should be recognized that they do not reflect the performance of a new FGD system specifically designed to attain a continuous compliance standard.

When the percent reduction standard was proposed, EPA projected the performance of newly designed FGD systems. The projection, referred to as the "line of improved performance" in the analysis, was principally based on the information on how to improve median system performance (OAQPS-78-1, III-B-4). The line showed that compliance with the proposed standard (85 percent reduction in potential SO_2 emissions, 24-hour average) could be attained with an FGD system if the only improvement made relative to an existing FGD system was to increase the median efficiency to 92 percent. The "line of improved performance" did not reflect the sulfur reduction credits that could be applied towards compliance with the proposed standard or the improvements in process control (less than 0.289 geometric standard deviation) that could be designed into a new facility. While these alternatives were discussed in detail and included within the basis for the proposed standard (OAQPS-78-1, III-B-4), the purpose of the "line of improved performance" was to show that even without credits or process control improvements, the proposed standard could be met. Upon proposal, the source owner was provided a choice of complying with the percent reduction standard by (1) an FGD system *alone* (85 percent reduction, 24-hour standard), or by (2) use of sulfur reduction credits together with an FGD system attaining less than 85 percent reduction.

After proposal, EPA continued to analyze regulatory options for establishing the final percent removal requirement. On December 8, 1978, economic analyses of these additional options were published in the **Federal Register** (43 FR 57834) for public comment. In this notice EPA stated that:

> Reassessment of the assumptions made in the August analysis also revealed that the impact of the coal washing credit had not been considered in the modeling analysis. Other credits allowed by the September proposal, such as sulfur removed by the pulverizers or in bottom ash and flyash, were determined not to be significant when viewed at the national and regional levels. The coal washing credit, on the other hand, was found to have a significant effect on predicated emissions levels and, therefore, was taken into consideration in the results presented here.

This statement gave notice that the effect of the coal washing credit on emission levels for the proposed control options had not been properly assessed in previous modeling anayses. In the economic analyses completed before proposal, the environmental benefits of the proposed standard were optimistic because it was assumed that all high-sulfur coal would be washed, but a corresponding reduction in the level of scrubbing needed for compliance was not taken into account. This error resulted in the analyses understimating the amount of national and regional SO_2 emissions that would have been allowed by the proposed standard. This problem was discussed at length at the public hearing on December 12, 1978 (OAQPS-78-1, IV-F-1, p. 11, 22, 28, and 29).

UARG addressed this question of coal washing in comments submitted in response to recommendations presented at the public hearing by the Natural Resources Defense Council (OAQPS-78-1, IV-F-1, p. 65, 12-12-78) that the final standards be based upon the removal of sulfur from fuel *together with* the removal of SO_2 from flue gases with a FGD system. In their comments (OAQPS-78-1, IV-D-725, Appendix A, p. 23), UARG had three main objections:

(1) All coals are not washable to the same degree.

(2) Coal cleaning may not be economically feasible.

(3) The Clean Air Act and the Resource Conservation and Recovery Act may preclude the construction of coal washing facilities at every mine.

EPA has reviewed these comments again and does not find that they change the Administrator's conclusion that washed coal can be used in conjunction with FGD systems to attain a 90 percent reduction in potential SO_2 emissions. First, EPA realizes that all coal is not equally washable. In the regulatory analaysis, the degree of coal washing was a function of the rank and sulfur content of the coal. Moreover, because of the variable control scale inherent in the standard, 75 percent of U.S coal reserves would require less than 90 percent reduction in potential SO_2 emissions. The remaining 25 percent are high sulfur coals on which the highest degree of sulfur removal by coal washing are acheived. Second, the washing assumptions used by the Agency reflected the percentage of sulfur removal currently being attained by conventional coal washing plants in the U.S. (OAQPS-78-1, IV-D-756). These washing percentages were therefore cost-feasible assumptions because they are typical of current washing practices. Finally, the Agency does not believe that environmental regulations will prohibit the cleaning of coal. The Clean Air Act and the Resource Conservation and Recovery Act may impose certain environmental controls, but would not prevent the routine construction of coal washing plants. Thus, the Agency concluded that the basis for the promulgated standard could be a combination of FGD control and fuel credits.

Based on these findings, EPA stated (44 FR 33582) that the 90 percent reduction standard "can be achieved at the individual plant level even under the most demanding conditions through the application of flue gas desulfurization (FGD) systems together with sulfur reductions achieved by currently practiced coal preparation techniques. Reductions achieved in the fly ash and

bottom ash are also applicable". Thus, FGD systems *together with* removal of sulfur from the fuel was the basis for the final standard. The standard prohibits the emission of more than "10 percent of the potential combustion concentration (90 percent reduction)." That is, the final standard requires 90 percent reduction of the potential emissions (the theoretical emissions that would result from combustion of fuel in an uncleaned state), not 90 percent removal by a scrubber.

Since UARG failed to take into consideration sulfur reduction credits, UARG analyzed a more stringent standard than was promulgated. Furthermore, EPA's review revealed that while the statistical methodology in the UARG analysis was basically correct, it was flawed by UARG's assumption about the process variation of a new FGD system. As a result, the statistical anaysis was improperly used by UARG to project the number of violations expected by a new FGD system.

To elaborate on the variability issue, page 14 of the UARG petition states:

> The range of efficiency variability values resulting from this analysis represents the range of efficiency variabilities that can be expected to be encountered at future FGD sites

This assumption artificially inflated the amount of variability that would reasonably be expected in a new FGD system because it presumed that there were no major design and operational differences in the existing FGD systems tested and that the performance of new systems would not improve beyond that of systems tested by EPA. To estimate process variability of new FGD systems, UARG simply averaged together all data from all systems tested including malfunctioning systems (Conesville). EPA's review of these data showed that there were major design and operating differences in the existing FGD systems tested and that the process control could be improved in new FGD systems (OAQPS-78-1, VI-B-14). Therefore, not all of the FGD systems tested by EPA were representative of best demonstrated technology for SO_2 control.

These major differences in the FGD systems tested are apparent when the test reports are examined (OAQPS-78-1, VI-B-14).One of the tests was conducted when the FGD systems were not operating properly (Conesville). Two tests were conducted on regenerative FGD systems (Philadelphia and Chicago) which are not representative of a lime or limestone FGD system. Another test was on an adipic acid/lime FGD system (Shawnee-venturi). None of these tests were representative of the process variation of well-operated, lime or limestone FGD systems on a high-sulfur coal application (OAQPS-78-1, VI-B-14).

Only three systems were tested when (1) the unit was operating normally, and (2) pH control instrumentation was in place and operational (Pittsburgh, Shawnee-TCA, and Louisville). Only at Shawnee did EPA purposely have skilled engineering and technician personnel closely monitor the operation during the test (OAQPS-78-1, VI-B-14). Data from these systems best describe the process control performance of existing lime/limestone FGD systems.

During the Pittsburgh test, there were some problems with pH meters. The data was separated into Test I (pH meter inoperative) and Test II (pH meter operative). During Test I, operators measured pH hourly with a portable instrument (OAQPS-78-1, VI-B-14). Analysis of these data show low process variation during each test period (OAQPS-78-1, VI-B-13). Although the process variation during the second test was 10 percent lower, the difference was not found to be statistically significant. Data taken during each test (I and II) are representative of control attainable with pH controls only. Boiler load was relatively stable during the test. Average process variation as described by the geometric standard deviation was 0.21 and 0.23, respectively.

At Shawnee, only pH controls were in use, but additional attention was given to controlling the process by technical personnel. Boiler load was purposely varied. Geometric standard deviation was 0.18, which was similar to that recorded at Pittsburgh. UARG acknowledged that careful attention to control of the FGD operation by skilled personnel was an important factor in control of the Shawnee-TCA scrubber process (OAQPS-78-1, II-D-440, page 3). It was at the Shawnee test that the best control of FGD process variability by an existing FGD system was demonstrated (OAQPS-78-1, II-B-13).

The Louisville test appears to represent a special case. The average process variation was significantly higher (0.30 and 0.34 for the two units tested) than was recorded at the two other tests (Pittsburgh and Shawnee). An EPA contractor identified two factors which potentially could adversely affect process control at Louisville (OAQPS-78-1, VI-B-14). First, they noted that Louisville was originally designed in the 1960's and has had significant retrofit design changes which could affect process control. Second, the degree of operator attention given to process control is unknown. In addition, UARG showed that an additional factor which may affect the FGD process control is boiler load changes. Unlike a new boiler, the Louisville unit is an older boiler which has been placed into peaking service and therefore experiences significant load changes during the course of a day. As was the case with Pittsburgh and Shawnee, Louisville only uses pH controls to regulate the process. The process variation was analyzed and the maximum process variation of the Louisville system, at a 95 percent confidence level, was determined to be 0.36 geometric standard deviation (OAQPS-78-1, VI-B-13). This estimate of process variation represents a "worst case" situation since it reflects the degree of FGD variability at a peaking unit rather than on the more easily controlled immediate- or base-loaded applications.

In addition to basing their projections on nonrepresentative systems, UARG has also ignored information in a background information document (OAQPS-78-1, II-B-4, section 4.2.6) on feasible process control improvements which were currently used in Japan (OAQPS-78-1, II-I-359). An appraisal of the degree of process instrumentation and control in use at the existing FGD systems tested and a review of the feasible process control improvements which can be designed into new FGD systems was also reviewed (OAQPS-78-1, VI-B-14). As described in this review, none of systems tested had automatic process instrumentation control in operation. All adjustments to scrubber operation were made by intermittent, manual adjustments by an operator. Automatic process controls, which provide immediate and continuous adjustments, can reduce the process control response time and the magnitude of FGD efficiency variation. Even the best controlled FGD systems tested (the Shawnee FGD system, which was designed in the 1960's) employed only feedback pH process control systems (OAQPS-78-1, IV-J-20). None of these existing FGD systems were designed with the feedforward process control features now used in Japan (OAQPS-78-1, II-I-359) for the automatic adjustment of scrubber make-up in response to changing operating conditions. These systems respond to boiler load changes or the amount of SO_2 in the flue gases to be cleaned before they impact the scrubbing system. The use of such systems would improve the control of short-term FGD efficiency variation. At the FGD systems tested, the actual flue gas SO_2

concentration (affected by coal sulfur content) and gas volume (affected by boiler load) was not routinely monitored by the FGD system operators for the purpose of controlling the FGD operation as is currently practiced in Japan (OAQPS–78–1, II–I–359). Thus, even the best controlled existing systems tested were not representative of the control of process variation that would be expected in the performance of new FGD systems to be operated in the 1980's (OAQPS–78–1, VI–B–14). For the purpose of describing the range in performance of an FGD system using only feedback pH control and which are known to have received close attention by operating personnel, the data recorded at these two existing FGD systems (Pittsburgh, test II and Shawnee-TCA) have been used by EPA to project the maximum process variation that would result (0.23 geometric standard deviation) at a 95 percent confidence interval for a base loaded boiler. The data from Louisville was used to represent performance of a peak loaded boiler (0.36 geometric standard deviation at the 95 percent confidence level). These values are conservative because the data collected at the existing FGD systems tested are not representative of the lower process variation that would be expected in future FGD systems designed with improved process control systems (OAQPS–78–1, VI–B–14).

EPA's statistical analysis of scrubber efficency is in close agreement with the UARG analysis when the same process variation and amount of autocorrelation was assumed. EPA's analysis showed about the same autocorrelation effect (the tendency for scrubber efficiency to follow the previous day's performance) as UARG's analysis. A "worst-case" 0.7 autocorrelation factor was used in both analyses even though a more favorable 0.6 factor could have been used based upon the measured autocorrelation of the data at the Shawnee-TCA and Pittsburgh tests. A comparison of the minimum 30-day average performance of a FGD system based upon EPA and UARG process variation assumptions is given in Table 5a.

The EPA analysis (OAQPS–78–1, VI–B–13) summarized in Tables 5a and 5b shows the median scrubbing efficieny required to achieve various minimum 30-day rolling average removal levels (probability of 1 violation in 10 years). The three sets of estimates shown are based on (1) the same process control demonstrated at Pittsburgh, test II and loaded, well-operated existing plant (σ_g=0.20 on average and σ_g=0.23 at the 95 percent confidence level), (2) the same process control demonstrated at Louisville which represents a peak loaded, existing plant (σ_g=0.32 on average and σ_g=0.36 at the 95 percent confidence level), and (3) the poor process control projected by UARG (σ_g=0.29 on average and σ_g=0.43 at the 95 percent confidence level). The process variation is described on a 24-hour, geometric standard deviation (σ_g) basis to allow comparison with UARG's analysis. However, the minimum FGD efficiencies shown in Tables 5a and 5b are 30-day rolling averages.

It is evident from the analysis summarized in Table 5a that if a new FGD system could be operated at least as well as the two best controlled existing FGD systems tested, a 92 percent efficient scrubber (median) can achieve between 88 and 89 percent control on a 30-day rolling average Shawnee-TCA, which represents a base basis.[1] More than 89 percent minimum reduction could be obtained if the process variations in new FGD systems are kept under better control with new control system instruments and careful attention by operating personnel. Even the peak-loaded Louisville system, which has much higher process variability (σ_g=0.32 on average), could achieve 86 to 87 percent reduction.

When reviewing the results of analyses contained in Tables 5a and 5b, it must be kept in mind that they represent "worst case" projections of compliance capability. Neither the UARG nor EPA projections took into account load shifting or the effect of a spare FGD module as a means of countering worst-case system performance (as portrayed by the 95 percent confidence level).

[1] With a risk assumption of one violation per year (the assumption used by UARG) the minimum 30-day rolling average was between 89 percent and 90 percent control at the 95 percent confidence level (OAQPS–78–1, VI–B–13, page 1–4).

Table 5a.—*Median FGD Efficiency to Attain Minimum 30-day Rolling Average Standard for Base Loaded Units* [a]

Minimum 30-day rolling average FGD efficiency	Median efficiency for existing well-controlled FGD systems tested [EPA basis]		Median efficiency for all existing FGD systems tested [UARG basis]	
	Average [σ_g=0.20]	Maximum [σ_g=0.23]	Average [σ_g=0.29]	Maximum [σ_g=0.43]
90	92.6	92.9	93.5	94.9
89	91.8	92.2	92.9	94.4
88	91.1	91.5	92.2	93.8
87	90.3	90.8	91.6	93.3
86	89.6	90.1	90.9	92.8
85	88.8	89.3	90.3	92.3

[a] Estimates are based on probability of only 1 violation in 10 years. Process variation (σ_g is expressed as one geometric standard deviation, 24-hour basis). The maximum process variation is projected at the 95th percentile.

Table 5b.—*Median FGD Efficiency to Attain Minimum 30-day Rolling Average Standard for Peak Loaded Units.* [a]

Minimum 30-day rolling average FGD efficiency	Median efficiency for peak loaded, existing FGD systems tested [EPA basis]	
	Average [σ_g=0.32]	Maximum [σ_g=0.36]
90	93.8	94.2
89	93.2	93.6
88	92.6	93.1
87	92.0	92.5
86	91.4	91.9
85	90.8	91.3

[a] Estimates are based on probability of only 1 violation in 10 years. Process variation (σ_g) is expressed as one geometric standard deviation, 24-hour basis. The maximum process variation is projected at the 95th percentile.

EPA also contended that an FGD system supplier could miss the mark in designing a 92 percent median efficiency FGD system and that a miscalculation of only 1 or 2 percent in median efficiency would prevent the FGD system from complying with the final SO_2 percent reduction standard (UARG petition, Appendix B, p. 64). EPA specifically addressed this miss-the-mark argument when it established a variable control standard (70 percent to 90 percent reduction). In the preamble to the final standard EPA stated, "Finally, under a variable approach, a source could move to a lower sulfur content coal to achieve compliance if its control equipment failed to meet design expectations" (44 FR 33583, left column). An FGD system designed for high-sulfur coal would increase in scrubbing efficiency if a lower-sulfur coal were fired, and the amount of removal required for compliance would drop from 90 percent to as low as 70 percent reduction in potential SO_2 emissions.

Even if, as UARG contends, an FGD system on a 30-day rolling average basis (through poor design or operating practices) could only attain 85 percent reduction, the facility would comply with the promulgated 90 percent reduction standard when credits for sulfur removed by coal washing, pulverizers, and in bottom and fly ash are considered. These credits which can

be substantial, are summarized as follows:

1. *Coal washing.* On high-sulfur midwestern coals that would be subject to the 90 percent reduction requirement, an average of 27 percent sulfur removal was achieved by conventional coal washing plants in 1978 (OAQPS–78–1, IV–D–761). Even in Ohio where the lowest average coal washing reduction was recorded, 20 percent reduction was attained. These data represent current industry practice and do not necessarily represent full application of state-of-the-art in coal cleaning technology.

2. *Coal pulverizers.* Additional sulfur reductions are also attainable with coal pulverizers used at power plants. Coal is typically pulverized at power plants prior to combustion. By selecting a specific type of coal pulverizer (one that will reject pyrites from the pulverized coal), sulfur can be removed. One utility company reported to EPA that sulfur reductions of 12% to 38% (with 24% average removal) had been obtained (OAQPS–78–1, II–D–179) by the pulvizers alone when a program had been implemented to optimize the rejection of pyrites by the pulverizer equipment.

3. *Ash retention.* One utility company has reported 0.4% to 5.1% sulfur removal credit in bottom ash alone with eastern and midwestern coals and 7.3% to 15.9% removal with a western coal (OAQPS–78–1, II–B–72). To determine how much sulfur is removed by the bottom ash and fly ash combined, EPA conducted a study in which numerous boilers were tested. The amount of SO_2 emitted was compared to the potential SO_2 emissions in the coal. For eight western coals and six midwestern coals, an average sulfur retention of 20 percent and 10 percent, respectively, was found (OAQPS–78–1, IV–A–6). Thus, an average of at least 10 percent SO_2 reduction can be attributed to sulfur retention in coal ash.

These credits *together with* an FGD system continuously achieving as little as 85 percent reduction are sufficient to attain compliance with the final SO_2 percent reduction standard as is shown in Table 6:

Table 6.—*Impact of Sulfur Reduction Credits on Required FGD Control Efficiencies to Attain 90 Percent Overall SO_2 Reduction*

SO_2 removal method	Compliance Option A	Compliance Option B	Option C
Coal washing removal, percent	27	20	8
Pulverizer, fly ash, and bottom ash reduction, percent	10	4	0
FGD system removal, percent	85	87	89
Overall SO_2 reduction in potential emissions	90	90	90

Table 6 illustrates that even if the FGD system attained only 85 percent reduction as UARG has claimed, the 90 percent removal standard would be achieved (Option A) even if a coal washing plant attained only 27 percent reduction in sulfur (the average reduction reported by the National Coal Association for conventional coal washing plants, OAQPS–78–1, IV–D–761). In addition, Table 6 illustrates that less fuel credit is needed when the FGD system attains more than 85 percent reduction (Options B and C). For example, even if the minimum amount of coal washing curently being achieved (20 percent in Ohio) is attained, only 87 percent FGD reduction would be needed. Thus, less than average or only average sulfur reduction credits (i.e., only 8–27% coal washing and 0–10% pulverizer, bottom ash and fly ash credits) would be needed to comply with the 90 percent reduction standard even if the FGD system *alone* only attained 85 to 89 percent control. Moreover, for 75 percent of the nation's coal reserves which have potential emissions less than 260 ng/J (6.0 lbs/million Btu) heat input (OAQPS–78–1, IV–E–12, page 18), less than 90 percent reduction in potential SO_2 emissions would be needed to meet the standard.

The statistical analysis submitted by UARG does not address the basis (FGD and sulfur reduction credits) of the standard and therefore does not alter the conclusions regarding the achievability of the promulgated percent reduction standard. The prescribed level can be achieved at the individual plant level even under the most demanding conditions through the application of scrubbers together with sulfur reduction credits.

Finally, UARG's petition (p. 15) states that the final standard was biased by an error in the preamble (see table, 44 FR 33592) which incorrectly referred to certain FGD removal efficiencies as "averages" rather than as geometric "means" (medians). These removal efficiencies were properly referred to as "means" in the EPA test reports. This discrepancy had no bearing on EPA's decision to promulgate a 90 percent SO_2 standard. Even though UARG claims a bias was introduced, their consultant's report states (see Appendix B, Page 46):

> Therefore, even though EPA mistakenly used the term "average SO_2 removal" in the promulgation, it is obvious that when the phrase "mean FGD efficiency" is used, EPA is correctly referred to the *mean* (or median) of the long-normal distribution of (1-eff).

Thus, even though Entropy (UARG's consultant which prepared their statistical analysis in Appendix B) "discovered a discrepancy" as UARG alleges, they did not reach a conclusion as UARG has done, that a simple transcription error in preparation of the preamble undermined the credibility of EPA's analysis of the test data. In fact, the analysis of test data performed by EPA (OAQPS–78–1, II–B–4) used correct statistical terminology.

The Sierra Club also submitted a petition that questioned the promulgated 90 percent, 30-day rolling average standard. The petition asks "why the final percentage of removal for 'full scrubbing' was set at only 90 percent for a 30-day average" in view of the preamble to the proposal which mentions a 92 percent reduction (43 FR 42159). The petition states that "EPA indicated that 85 percent scrubbing on a 24-hour average was equivalent to 92 percent on a 30-day average." This statement is a misquotation. The preamble actually stated that "an FGD system that could achieve a 92 percent long-term (30 days or more) mean SO_2 removal would comply with the proposed 85 percent (24-hour average) requirement." The long-term mean referred to is the median value (geometric mean) of FGD system performance, not an equivalent standard. Reference in the preamble was made to the background information supplement (OAQPS–78–1, III–B–4) which provided "a more detailed discussion of these findings." The 92 percent removal is described therein as the median (geometric mean) of the statistical distribution defined by the "line of improved performance" in Figure 4–1. A median is the middle number in a given sequence of numbers. Thus for a sequence of 24-hour or 30-day rolling average efficiencies, the median SO_2 removal (92 percent) is a level at which one-half of the 30-day rolling average FGD system efficiencies would be higher and one-half would be lower. Since one-half of the expected removal efficiencies would be lower than the 92 percent median, a standard could not be set at that level. The standard must recognize the range of 30-day rolling average FGD efficiencies that would be expected. The petition is based upon a misconception as to the meaning of the 92 percent value (a median) and is therefore not new information of central relevance to this issue.

The Environmental Defense Fund requested that EPA consider the relevance of the lime/limestone-adipic acid tests at Shawnee to this rulemaking. Adipic acid has been found to increase FGD system performance by limiting the drop in pH that normally occurs at the gas/liquid interface during SO_2 absorption. Test runs at Shawnee

showed increased FGD performance (in one test series the efficiency increased from 71 percent to 93 percent) with no apparent adverse impact upon FGD system operation.

EPA agrees that use of adipic acid additive in lime/limestone scrubbing solutions appears very promising and is currently planning a full-scale FGD system demonstration. Several important areas are to be evaluated in the EPA test program. The handling and disposal characteristics of waste sludges from the scrubber must be evaluated to see that adipic acid does not affect control of leachates into groundwater. In addition, the consumption rate of adipic acid by the FGD system and its ultimate disposition must be evaluated. Furthermore, tests must be conducted to show whether or not the concentration of adipic acid in FGD system sludge poses significant environmental problems. In the absence of such data, EPA does not believe it prudent to include adipic acid as a basis for the current revised standard.

IV. Particulate Matter Standards

Only one of the four petitions for reconsideration raised issues concerning the particulate matter standard. In their petition, the Utility Air Regulatory Group (UARG) argued principally that baghouse technology was not demonstrated on large coal-fired utility boilers and that the 13 ng/J (0.03 lb/million Btu) heat input standard could not be achieved at reasonable costs with electrostatic precipitators on low-sulfur coal applications. They also noted that emission test data on a 350 MW baghouse application was placed in the record after the close of the comment period. In response to these data, UARG presented operating information on baghouse systems obtained from two coal-fired installations. In addition they restated arguments that had been raised in their January 1979 comments concerning EPA's data base and the potential effects of NO_x and SO_2 emission control on particulate emissions.

In reaching his decision that baghouse technology is adequately demonstrated, the Administrator took into account a number of factors. In addition to the emission test data and other technical information contained in the record, he placed significant weight on the fact that at least 26 baghouse-equipped coal-fired electric utility steam generators were operating prior to promulgation of the standard and that 26 additional units were planned to start operation by the end of 1982. He also noted that some of the utility companies operating baghouses on coal-fired steam generators were ordering more baghouses and that none of them had announced plans to decommission or retrofit a baghouse controlled plant because of operating or cost problems. The Administrator believed that this was a strong indication that some segments of the utility industry believe that baghouses are practical, economical, and adequately demonstrated systems for control of particulate emissions. These electric utility baghouses are being applied to a wide range of sizes of steam generators and to coals of varying rank and sulfur content. The Industrial Gas Cleaning Institute speaking for the manufacturers of baghouses submitted comments (OAQPS-78-1, IV-D-247) confirming that baghouses are adequately demonstrated systems for control of particulate emissions from coal-fired steam-electric generators of all sizes and types.

In the proposal, EPA acknowledged that large baghouses of the size that would typically be used to meet the standard had only been recently activated. Further, the Agency announced that it planned to test a 350 MW unit (43 FR 42169, center column). The validated test data from this unit, located at the Harrington Station, demonstrated that the standard could be achieved at large facilities (OAQPS-78-1, V-B-1, page 4-1). The Agency also became aware that the operators of the facility were encountering start-up problems. After carefully evaluating the situation, the Agency concluded that the problems were temporary in nature (44 FR 33585, left column).

Furthermore, Appendix E of the UARG petition supports the Agency finding. According to Appendix E, the start-up problems experienced at Harrington Station (Unit #2) have not affected unit availability nor have they altered the utility's plans for equipping another large coal-fired steam generator at the site (Unit #3) with a baghouse. Appendix E noted, "The company feels that the baghouse achieved an availability equal to that of the electrostatic precipitator installed in unit 1" (UARG petition, Appendix E, page 2). The Appendix also examined two retrofit baghouse installations on boilers firing Texas lignite at the Monticello Station (Unit #1 and Unit #2). While the first unit that came on line experienced problems, Appendix E notes, "Since the start-up of Unit 2 bag filter, the baghouse has been operational at all times the boiler was on line (due to the solution of the majority of the problems associated with Unit 1 baghouse)" (UARG petition, Appendix E, page 5). These findings served to reinforce the Agency's conclusion that problems encountered at these initial installations are correctible.

Based on the Harrington and Monticello experience, UARG maintained that EPA did not properly consider the cost of activating and maintaining a baghouse. Contrary to UARG's position, the cost estimates developed by EPA provide liberal allowances for start-up and continued maintenance. For example, the Agency's cost estimates for a baghouse for a 350 MW power plant provided over $1.4 million for start-up and first year maintenance of which $440,000 was included for bag replacement (OAQPS-78-1, II-A-64 and VI-B-12). For subsequent years, $710,000 per year was allowed for routine maintenance of which $440,000 was included for bag replacement. In comparison, the UARG petition indicated that bag replacement costs during the first year of operation of the baghouse at the Harrington Station (350 MW capacity) would be $250,000 and the bag replacement costs at the two Monticello baghouse units (610 MW capacity total) would total about $642,000. From the information provided by UARG, it appears that the Agency has fully accounted for any potential costs that may be incurred during start-up or annual maintenance.

UARG further maintained that higher pressure drops encountered at these initial installations would increase the cost of power to operate a baghouse beyond those estimated by the Agency. The Administrator agrees that if higher pressure drops are encountered an increase in cost will be incurred. However, even assuming that the pressure drops initially experienced at the Harrington and Monticello Stations occur generally, the annual cost will not increase sufficiently to affect the Administrator's decision that the standard can be achieved at a reasonable cost. For example, the increase in pressure drop reported by UARG (UARG petition, page 43) at the Harrington station would result in a cost penalty of about $191,000 per year, which represents only a 4.5 percent increase in the total annualized baghouse costs projected by EPA (OAQPS-78-1, II-A-64, page 3-18) and

less than one percent increase in relation to utility operating costs. It should be reported, however, that as a result of corrective measures taken at Harrington station since start-up, the operating pressure drop reported by UARG has been reduced. If the pressure drop stabilizes at this improved level 2 kilopascals (8 inches H_2O) rather than the 2.75 kilopascals (11 inches H_2O) suggested by UARG the $191,000 cost penalty would be reduced by some $90,000 per year (OAQPS–78–1, VI–B–11 and UARG petition, page 43).

UARG also maintained that a period longer than 180 days after start-up is required to shake down new baghouse installations, and that EPA should amend 40 CFR 60.8, which requires compliance to be demonstrated within 180 days of start-up. UARG based these comments on the experience at the Harrington and Monticello Stations. It is important to understand that 40 CFR 60.8 only requires compliance with the emission standards within 180 days of start-up and does not require, or even suggest, that the operation of the facility be optimized within that time period. Optimization of a system is a continual process based on experience gained with time. On the other hand, a system may be fully capable of compliance with the standard before it is fully optimized.

In the case of the Harrington station the initial performance test was conducted by the utility during October 1978 (which was within four months of start-up). The initial test and a subsequent one were found however, to be invalid due to testing errors and therefore it was February 1979 before valid test results were obtained for the Harrington Unit (OAQPS–78–1, IV–B–1, page 42). This test clearly demonstrated achievement of the 13 ng/J (0.03 lb/million Btu) heat input emission level. These results were obtained even though the unit was still undergoing operation and maintenance refinements. With respect to the Monticello station, UARG reported that no actual performance test data are available (UARG petition, Appendix E, page 6).

UARG also maintained that baghouses are not suitable for peaking units because of the high energy penalty associated with keeping the baghouse above the dew point. EPA recognizes that baghouses may not be the best control device for all applications. In those instances where high energy penalties may be incurred in heating the baghouse above the dew point, the utility would have the option of employing an electrostatic precipitator. However, some utilities will be using baghouses for peaking units. For example, the baghouse control system on four subbituminous, pulverized coal-fired boilers at the Kramer Station have been equipped with baghouse preheat systems and that station will be placed in peaking service in the near future (OAQPS–78–1, VI–B–10).

UARG also argued that it may be necessary to install a by-pass system in conjunction with a baghouse to protect the baghouse from damage during certain operation modes. The use of such a system during periods of start-up, shutdown, or malfunction is allowed by the standard when in keeping with good operating practice.

The UARG petition implied that the test data base for electrostatic precipitator systems (ESP) is inadequate for determining that such systems can meet the standard. Contrary to UARG's position, the EPA data base for the standard included test data obtained under worst-case conditions, such as (1) when high resistivity ash was being collected, (2) during sootblowing, and (3) when no additives to enhance ESP performance were used (OAQPS–78–1, III–B–1, page 4–11 and 4–12). Even when all of the foregoing worst-case conditions were incurred simultaneously, particulate matter emission levels were still less than the standard. It should also be understood that none of the ESP systems tested were larger than the model sizes used for estimating the cost of control under worst-case conditions.

The UARG petition also questioned the Administrator's reasoning in failing to evaluate the economic impact of applying a 197 square meter per actual cubic meter per second (1000 ft ^{2}/1000 ACFM) cold-side ESP to achieve the standard under adverse conditions such as when firing low-sulfur coal. The Administrator did not evaluate the economic impact of applying a large, cold-side ESP because a smaller, less costly 128 square meter per actual cubic meter per second (650 ft ^{2}/1000 ACFM) hot-side ESP would typically be used. The Administrator believed that it would have been non-productive to investigate the economics of a cold-side ESP when a hot-side ESP would achieve the same level of emission control at a lower cost.

The UARG petition also suggested that hot-side ESP's are not always the best choice for low-sulfur coal applications. The Administrator agrees with this position. In some case, low-sulfur coals produce an ash which is relatively easy to collect since flyash resistivity is not a problem. Under such conditions it would be less costly to apply a cold-side ESP and therefore it would be the preferred approach. However, when developing cost impacts of the standard, the Agency focused on typical low-sulfur coal applications which represents worst case conditions, and therefore assessed only hot-side precipitators.

The UARG petition suggests that in some cases the addition of chemical additives to the flue gas may be required to achieve the standard with ESPs, and the Agency should have fully assessed the environmental impact of using such additives. The Administrator, after assessing all available data, concluded that the use of additives to improve ESP performance would not be necessary (OAQPS–78–1, III–B–1, page 4–11). Therefore, it was not incumbent upon EPA to account for the environmental impact of the use of additives other than to note that such additives could increase SO_3 or acid mist emissions. In instances where a utility elects to employ additives as a cost saving measure, their potential effect on the environment can be assessed on a case-by-case basis during the new source review process.

UARG also maintained that there are special problems with some low-sulfur coals that would preclude the use of hot-side ESPs and attached Appendix F in support of their position. Review of Appendix F reveals that while the author discussed certain problems related to the application of hot-side ESPs on some western low-sulfur coal, he also set forth effective techniques for resolving these problems. The author concluded, "The evidence of more than 11 years of experience indicates that hot precipitators are here to stay and very likely their use on all types of coal will increase."

UARG also argued that the data base in support of the final particulate standard for oil-fired steam generating units was inadequate. The standard is based on a number of studies of particulate matter control for oil-fired boilers. These studies were summarized and referenced in the BID for the proposed standard (OAQPS–78–1, III–B–1, page 4–39). These earlier studies (*Control of Particulate Matter from Oil Burners and Boilers*, April 1976, EPA–450/3–76–005; and *Particulate Emission Control Systems for Oil-fired Boilers*, December 1974, EPA–450/3–74–063) support the conclusion that ESP control systems are applicable to oil-fired steam generators and that such emission control systems can achieve the standard. The achievability of the standard was also confirmed by the Hawaiian Electric Company, a firm that would be significantly affected by the standard since virtually all their new

generating capacity will be oil-fired due to their location. In their comments the company indicated, "Hawaiian Electric Company supports the standards as proposed in so far as they impact upon the electric utilities in Hawaii" (OAQPS–78–1, IV–D–159).

UARG also argued that the Administrator had little or no data upon which to base a conclusion that the particulate standard is achievable for lignite-fired units. In making this assertion, UARG failed to recognize that the Agency had extensively analyzed lignite-fired units in 1976 and concluded that they could employ the same types of control systems as those used for other coal types (EPA–450/2–76–030a, page II–29). Additionally, review of the literature and other sources revealed no new data that would alter this finding (Some of the data considered includes OAQPS–78–1, II–I–59, II–I–312, and II–I–322) and the Agency continues to believe that the emission standards are achievable when firing all types of coal including lignite coal. UARG has not provided any information during the comment period or in their petition which would suggest any unique problems associated with the control of particulate matter from lignite-fired units.

The UARG petition alleged that the Administrator did not take into account the effect of NO_x control in conjunction with promulgation of the particulate standard. In developing the NO_x standard, the Administrator assessed the possibility that NO_x controls may increase ash combustibles and thereby affect the mass and characteristics of particulate emissions. The Administrator concluded, however, that the NO_x standard can be achieved without any increase in ash combustibles or any significant change in ash characteristics and therefore there would be no impact on the particulate standard (OAQPS–78–1, III–B–2, page 6–14).

UARG also raised the issue of sulfate carryover from the scrubber slurry and its potential effect on particulate emissions. EPA initially addressed this issue at proposal and concluded that with proper mist eliminator design and maintenance, liquid entrainment can be controlled to an acceptable level (43 FR 42170, left column). Since that time, no new information has been presented that would lead the Administrator to reconsider that finding.

In summary, UARG failed to present any new information on particulate matter control that is centrally relevant to the outcome of the rule.

V. NO_x Standards

The Utility Air Regulatory Group (UARG) sought reconsideration of the NO_x standards. They maintained that the record did not support EPA's findings that the final standards could be achieved by all boiler types, on a variety of coals, and on a continuous basis without an unreasonable risk of adverse side effects. In support of this position, they argued that while EPA's short-term emissions data provided insight into NO_x levels attainable by utility boilers under specified conditions during short-term periods, they did not sufficiently support EPA's standards based on continuous compliance. Further, they maintained that the continuous monitoring data relied on by the Agency does not support the general conclusions that all boiler types can meet the standards on a variety of coals under all operating conditions. They also argued that the Agency failed to collect or adequately analyze data on the adverse side effects of low-NO_x operations. Finally, they contended that vendor guarantees have been shown not to support the revised standards. The arguments presented in the petition were discussed in detail in an accompanying report prepared by UARG's consultant.

In general, the UARG petition merely reiterated comments submitted in January 1979. Their arguments concerning short-term test data, the potential adverse side effects of low-NO_x operation, and manufacturer's guarantees did not reflect new information nor were they substantially different from those presented earlier. For example, in their petition, UARG asserted that new information received at the close of comment period revealed that certain data EPA relied upon to conclude that low-NO_x operations do not increase the emissions of polycyclic organic matter (POM) are of questionable validity (UARG petition, page 56). This comment repeats the position stated in UARG's January 15, 1979, submittal (OAQPS 78–1, IV–D–611, attachment—KVB report, January 1979, page 86). More importantly, UARG failed to recognize that EPA did not rely on the tests in question and that the Agency noted in the BID for the proposed standards (OAQPS–78–1, III–B–2, page 6–12) that the data were insufficient to draw any conclusion on the effects of modern, low-NO_x Babcock and Wilcox burners on POM emissions. Instead, EPA based its conclusions in regard to POM on its finding that combustion efficiency would not decrease during low-NO_x operation and therefore, there would not be an increase in POM emissions (43 FR 42171, left column and OAQPS–78–1, III–B–2, page 9–6).

Similarly, UARG did not present any new data in regard to boiler tube corrosion. They merely restated the arguments they had raised in their January 1979 comments which questioned EPA's reliance on corrosion test samples (coupons). EPA believes that proper consideration has been given to the corrosion issues and substantial data exist to support the Administrator's finding that the final requirements are achievable without any significant adverse side effect (44 FR 33602, left column). In addition, UARG also maintained that the Agency should explain why it dismissed the 190 ng/J (0.45 lb/million Btu) heat input NO_x emission limit (44 FR 33602, right column) applicable to power plants in New Mexico. In dismissing the recommendation that the Agency adopt a 190 ng/J emission limit, the Administrator noted that the only support for such an emission limitation was in the form of vendor guarantees.

In relation to vendor guarantees, UARG maintained in their January comments and reiterate in their petition that EPA should not rely on vendor guarantees as support for the revised standards. EPA cannot subscribe to UARG's narrow position. While vendor guarantees alone would not provide a sufficient basis for a new source performance standard, EPA believes that consideration of vendor guarantees when supported by other findings is appropriate. In this instance, the vendor guarantees served to confirm EPA findings that the boiler manufacturers possess the requisite technology to achieve the final emission limitations. This approach was described by Foster Wheeler in their January 3, 1979, letter to UARG, (OAQPS 78–1, IV–D–611, attachment—KVB report, January 1979, page 119) that states, "When a government regulation, which has a major effect on steam generator design, is changed it is unreasonable to judge the capability of a manufacturer to meet the new regulation by evaluating equipment designed for the older less stringent regulation."

This observation is also germane to the arguments raised by UARG with respect to EPA data on short-term emission tests and continuous monitoring. In essence, UARG maintained that the EPA data base was inadequate because boilers designed and operated to meet the old 300 ng/J (0.7 lb/million Btu) heat input limitation under Subpart D have not been shown to be in continuous compliance with the

new standard under Subpart Da. While this statement is true, these units, which were designed and operated to meet the old standard, incurred only five exceedances of the new standards on a monthly basis. Moreover, a review of the available 34 months of continuous monitoring data from six utility boilers revealed that they all operated well below the applicable standard (OAQPS-78-1, V-B-1).

In addition, UARG argued that the available continuous monitoring data demonstrated that the Agency should not have relied on short-term test data. Citing Colstrip Units 1 and 2, they noted that less than one-third of the 30-day average emissions fell below the units' performance test levels of 125 ng/J (0.29 lb/million Btu) heat input and 165 ng/J (0.38 lb/million Btu) heat input, respectively. They further maintained that this had not been considered by the Agency. In fact, the Administrator recognized at the time of promulgation that emission values obtained on short-term tests could not be achieved continuously because of potential adverse side effects and therefore established emission limits well above the values measured by such tests (44 FR 42171, left column). In addition, EPA took into account the emission variability reflected by the available continuous monitoring data when it established a 30-day rolling average as the basis of determining compliance in the standards (44 FR 33586, left column).

UARG also maintained in their petition that EPA should not rely on the Colstrip continuous monitoring data because it was obtained with uncertified monitors. The Administrator recognized that the Colstrip data should not be relied on in absolute terms since monitors were probably biased high by approximately 10 percent (OAQPS 78-1, III-B-2, page 5-7). EPA's analysis of data revealed, however, that it would be appropriate to use the data to draw conclusions about variability in emissions since the shortcoming of the Colstrip monitors did not bias such findings. This data together with data obtained using certified continuous monitors at five other facilities (OAQPS 78-1, V-B-1, page 5-3) and the results from 30-day test programs (manual tests performed about twice per day) at three additional plants (OAQPS 78-1, II-B-62 and II-B-70) enabled the Administrator to conclude that emission variability under low-NO_x operating conditions was small and therefore the prescribed emission levels are achievable on a continuous basis.

UARG argued that since the only continuous monitoring data available was obtained from boilers manufactured by Combustion Engineering and on a limited number of coal types, the Agency did not have a sufficient basis for finding that the standards can be achieved by other manufacturers or when other types of coals are burned. The Administrator concluded after reviewing all available information that the other three major boiler manufacturers can achieve the same level of emission reduction as Combustion Engineering with a similar degree of emission variability (43 FR 42171, left column and 44 FR 33586, middle column). This finding was confirmed by statements submitted to UARG and EPA by the other vendors that their designs could achieve the final standards, although they expressed some concern about tube wastage potential (OAQPS-78-1, III-D-611, attachment-KVB report, pages 116-121 and IV-D-30). EPA has considered tube wastage (corrosion) throughout the rulemaking and has determined that it will not be a problem at the NO_x emission levels required by the standards (44 FR 33602, left column). With respect to different coal types, the Agency concluded from its analysis of available data that NO_x emissions are relatively insensitive to differing coal characteristics and therefore other coal types will not pose a compliance problem (43 FR 42171, left column and OAQPS-78-1, IV-B-24). UARG did not submit any data to refute this finding.

UARG also argued that the continuous monitoring data should have been accompanied by data on boiler operating conditions. EPA noted that the data were collected during extended periods representative of normal operations and therefore it reflected all operational transients that occurred. In particular, at Colstrip units 1 and 2 more than one full year of continuous monitoring data was analyzed for each unit. In view of this, EPA believes that the data base accurately reflects the degree of emission variability likely to be encountered under normal operating conditions. UARG recognized this in principle in their January 15 comments (Part 4, page 15) when they stated that "continuous monitors would measure all variations in NO_x emissions due to operational transients, coal variability, pollution control equipment degradation, etc."

In their petition, UARG restated their January 1979 comments that EPA's short-term test data were not representative and therefore should not serve as a basis for the standard. As noted earlier, EPA did not rely exclusively on short-term test data in setting the final regulations. In addition, contrary to the UARG claim, EPA believes that the boiler test configurations used to achieve low-NO_x operations reflect sound engineering judgement and that the techniques employed are applicable to modern boilers. This is not to say that the boiler manufacturers may not choose other approaches such as low-NO_x burners to achieve the standards. While recognizing that EPA's test program was concentrated on boilers from one manufacturer, sufficient data was obtained on the other major manufacturers' boilers to confirm the Agency's finding that they would exhibit similar emission characteristics (44 FR 33586, left column). Therefore, in the absence of new information, the Administrator has no basis to reconsider his finding that the prescribed emission limitations are achievable on modern boilers produced by all four major manufacturers.

VI. Emission Measurement and Compliance Determination

The Utility Air Regulatory Group (UARG) raised several issues pertaining to the accuracy and reliability of continuous monitors used to determine compliance with the SO_2 and NO_x standards. UARG particularly commented on the data from the Conesville Station. In addition, they also maintained that the sampling method for particulates was flawed. With respect to compliance determinations, UARG maintained that the method for calculating the 30-day rolling averages should be changed so that emissions before boiler outages are not included since they might bias the results. In addition, UARG argued that the standards were flawed since EPA had not included a statement as to how the Agency would consider monitoring accuracy in relation to compliance determination. With the exception of the method of calculating the 30-day rolling average and the comments on the Conesville station, the petition merely reiterated comments submitted prior to the close of the public comment period.

As to the reliability and durability of continuous monitors, information in the docket (OAQPS-78-1, II-A-88, IV-A-20, IV-A-21, and IV-A-22) demonstrates that on-site continuous monitoring systems (CMS) are capable and have operated on a long-term basis producing data which meet or exceed the minimum data requirements of the standards.

In reference to the Conesville project, UARG questioned why EPA dismissed the continuous monitoring results since it was the only long-term monitoring effort by EPA to gain instrument

operating experience. UARG maintained that this study showed monitor degradation over time and that it was representative of state-of-the-art monitoring system performance. This conclusion is erroneous. EPA does not consider the Conesville project adequate for drawing conclusions about monitor reliability because of problems which occurred during the project.

To begin with, UARG is incorrect in suggesting that the goal of the project was to obtain instrument operating experience. The primary purpose of the project was to obtain 90 days of continuous monitoring data on FGD system performance. Because of intermittent operation of the steam generator and the FGD system, this objective could not be achieved. As the end of the 90-day period approached, a decision was made to extend the test duration from three to six months. The intermittent system operation continued. As a result, when the FGD outages were deleted from the total project time of six months, the actual test duration was similar to those at the Louisville, Pittsburgh, and Chicago tests and did not, therefore, represent an extended test program.

EPA does not consider the Conesville results to be representative of state-of-the-art monitoring system performance. Because of the intermittent operation throughout the test period (OAQPS–78–1, IV–A–19, page 2), it became obvious that the goals of the program could not be met. As a result, monitoring system maintenance lapsed somewhat. For example, an ineffective sample conditioning system caused differences in monitor and reference method results (OAQPS–78–1, IV–A–20, page 3–2). If the EPA contractor had performed more rigorous quality assurance procedures, such as a repetition of the relative accuracy tests after monitor maintenance more useful results of the monitor's performance would have been obtained. Thus, the Conesville study re-emphasized the need for periodic comparisons of monitor and reference method data and the inherent value of sound quality assurance procedures.

The UARG petition suggested that the standards incorporate a statement as to how EPA will consider monitoring system accuracy during compliance determination. More specifically, UARG recommended that EPA define an error band for continuous monitoring data and explicitly state that the Agency will take no enforcement action if the data fall within the range of the error band. The Agency believes that such a provision is inappropriate. Throughout this rulemaking, EPA recognized the need for continuous monitoring systems to provide accurate and reproducible data. EPA also recognized that the accuracy of a CMS is affected by basic design principals of the CMS and by operating and maintenance procedures. For these reasons, the standards require that the monitors meet (1) published performance specifications (40 CFR Part 60 Appendix B) and (2) a rigorous quality assurance program after they are installed at a source. The performance specifications contain a relative accuracy criterion which establishes an acceptable combined limit for accuracy and reproducibility for the monitoring system. Following the performance test of the CMS, the standards specify quality assurance requirements with respect to daily calibrations of the instruments. As was noted in the rulemaking (44 FR 33611, right column), EPA has initiated laboratory and field studies to further refine the performance requirements for continuous monitors to include periodic demonstration of accuracy and reproducibility. In view of the existing performance requirements and EPA's program to further develop quality assurance procedures, the Administrator believes that the issue of continuous monitoring system accuracy was appropriately addressed. In doing so, he recognized that any questions of accuracy which may persist will have to be assessed on a case-by-case basis.

The UARG petition also raised as an issue the calculation of the 30-day rolling average emission rate. UARG maintained that the use of emission data collected before a boiler outage may not be representative of the control system performance after the boiler resumes operation. UARG indicated that boiler outage could last from a few days to several weeks and suggested that if an outage extends for more than 15 days, a new compliance period should be initiated. UARG also suggested that if a boiler outage is less than 15 days duration and the performance of the emission control system is significantly improved following boiler start-up, a new compliance period should be initiated. UARG argued that the data following start-up would be more descriptive of the current system performance and hence would provide a better basis for enforcement.

A basic premise of this rulemaking was that the standard should encourage not only installation of best control systems but also effective operating and maintenance procedures (44 FR 33595 center column, 33601 right column, and 33597 right column). The 30-day rolling average facilitates this objective. In selecting this approach, the Agency recognized that a 30-day average better reflects the engineering realities of SO_2 and NO_x control systems since it affords operators time to identify and respond to problems that affect control system efficiency. Daily enforcement (rolling average) was specified in order to encourage effective operating and maintenance procedures. Under this approach, any improvement in emission control system performance following start-up will be reflected in the compliance calculation along with efficiency degradations occurring before the outage. Therefore, the 30-day rolling average provides an accurate picture of overall control system performance.

On the other hand, the UARG suggestion would provide a distorted description of system performance since it would discount certain episodes of poor control system performance. That is, the system operator could allow the control system to degrade and then shut-down the boiler before a violation of the standard occurred. After start-up and any required maintenance, a new compliance period would commence, thereby excusing any excursions prior to a shut-down. In addition, since a new averaging period would be initiated the Agency would be unable to enforce the standard for the first 29 boiler operating days after the boiler had resumed operation. In the face of this potential for circumvention of the standards, the Administrator rejects the UARG approach.

UARG also reiterated their previous comments that EPA did not properly consider the accuracy and precision of Reference Method 5 for measuring particulate concentrations at or below 13 ng/J (0.03 lb/million Btu) heat input. EPA has recognized throughout this rulemaking that obtaining accurate and precise measurements of very low concentrations of particulate matter is difficult. In view of this, detailed and exacting procedures for the clean-up and analyses of the sample probe, filter holder, and the filter were specified in Method 5 to assure accuracy in determining the mass collected. Additionally, EPA has required that the sampling time be increased from 60 minutes to 120 minutes. This will increase the total sample volume from a minimum of 30 dscf to 60 dscf, thus increasing the total mass collected to about 100 mg at a loading of 13 ng/J (0.03 lb/million Btu) heat input. EPA has concluded that measurement of mass at this level can be reproduced within ±10 percent.

UARG also maintained that less than ideal sampling can cause particulate emission measurements to be inaccurate

and this has not been evaluated. EPA has addressed the question of determining representative locations and the number of sampling points in some detail in the reference methods and appropriate subparts. These procedures were designed to assure accurate measurements. EPA has also evaluated the effects of less than ideal sampling locations and concluded that generally the results would be biased below actual emissions. Assessment of the extent of possible biases in measurement data, however, must be made on a case-by-case basis.

UARG raised again the issue of acid mist generated by the FGD system being collected in the Reference Method 5 sample, therefore rendering the emission limit unachievable. EPA has recognized this problem throughout the rulemaking. In response to the Agency's own findings and the public comments, the standards permit determination of particulate emissions upstream of the scrubber. In addition, EPA announced that it is studying the effect of acid mist on particulate collection and is developing procedures to correct the collected mass for the acid mist portion.

VII. Applicability of Standards

Sierra Pacific Power Company and Idaho Power Company (collectively, "Sierra Pacific") petitioned the Administrator to reconsider the definition of "affected facility," asking that the applicability date of the standards be established as the date of promulgation rather than the date of proposal. 40 CFR 60.40a provides:

> (a) The affected facility to which this subpart applies is each electric utility steam generating unit:
>
> * * *
>
> (2) For which construction or modification is commenced after September 18, 1978.

September 19, 1978, is the date on which the proposed standard was published in the **Federal Register**. EPA based this definition on sections 111(a)(2) and 111(b)(6) of the Act. Section 111(a)(2) provides:

> The term "new source" means any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.

Section 111(b)(6) includes a similar provision specifically drafted to govern the applicability date of revised standards for fossil-fuel burning sources (of which this standard is the chief example.) It provides:

> Any new or modified fossil fuel-fired stationary source which commences construction prior to the date of publication of the proposed revised standards shall not be required to comply with such revised standards.

Sierra Pacific does not dispute that the Agency's definition of affected facility complies with the literal terms of sections 111(a)(2) and 111(b)(6). Sierra Pacific maintains, however, that the definition is unlawful, because the standard was promulgated more than 6 months after the proposal, in violation of sections 111(b)(1)(B) and 307(d)(10). Section 111(b)(1)(B) provides that a standard is to be promulgated within 90 days of its proposal. Section 307(d)(10) allows the Administrator to extend promulgation deadlines, such as the 90-day deadline in section 111(b)(1)(B), to up to 6 months after proposal. Sierra Pacific argues that section 111(a)(2) does not apply unless the deadlines in sections 111(b)(1)(B) and 307(d)(10) are met. In this case the final standard was promulgated on June 11, 1979, somewhat less than 9 months after proposal. (It was announced by the Administrator at a press conference on May 25, 1979, and signed by him on June 1, 1979.)

In the Administrator's view, the applicability date is properly the date of proposal. First, the plain language of section 111(a)(2) provides that the applicability date is the date of proposal. Second, the legislative history of section 111 shows that Congress did not intend that the applicability date should be the date of proposal only where a standard was promulgated within 90 days of proposal. Section 111(a)(2) took its present form in the conference committee bill that became the 1970 Clean Air Act Amendments, whereas the 90-day requirement came from the Senate bill, and there is no indication that Congress intended to link these two provisions.[2]

Moreover, this interpretation represents longstanding Agency practice. Even where responding to public comments delays promulgation more than 90 days, or more than 6 months, after proposal, the applicability dates of new source performance standards are established as the date of proposal. See 40 CFR Part 60, Subparts D *et seq.*

Sierra Pacific argues that its position has been adopted by EPA in "analogous" circumstances under the Clean Water Act. This is inaccurate. Section 306 of the Clean Water Act specifically provides that the date of proposal of a new source standard is the applicability date only if the standard is promulgated within 120 days of proposal (section 306(a)(2), (b)(1)(B)).

Sierra Pacific suggests that utilities are "unfairly prejudiced" by the applicability date, but does not submit any information to support this claim. In any event, there does not seem to be any substantial unfair prejudice. At the time of proposal, the Administrator had not decided whether a full or partial control alternative should be adopted in the final SO_2 standard. As a result, the Administrator proposed the full control alternative stating (43 FR 42154, center column):

> * * * the Clean Air Act provides that new source performance standards apply from the date they are proposed and it would be easier for power plants that start construction during the proposal period to scale down to partial control than to scale up to full control should the final standard differ from the proposal.

In fact, the final SO_2 standard was less stringent than the proposed rule.

In this case, utilities were on notice on September 19, 1978, of the proposed form of the standard, and that the standard would apply to facilities constructed after that date. In March 1979, it became clear to the Agency that it would not be possible to respond to all the public comments and promulgate the final standards by March 19, as required by the consent decree in *Sierra Club* v. *Costle*, a suit brought to compel promulgation of the standard. (The comment period had only closed on January 15; EPA had received over 625 comment letters, totalling about 6,000 pages, and the record amounted to over 21,000 pages.) The Agency promptly contacted the other parties to *Sierra Club* v. *Costle*, and all the parties jointly filed a stipulation that the standand should be signed by June 1 and that the Administrator should not seek "any further extensions of time." This stipulation was well-publicized (see, for example, 9 Environment Reporter Current Developments 2246, March 30, 1979). Thus utilities such as Sierra Pacific had reasonable assurance that the standard would be signed by June 1, as it was.

Even assuming, as Sierra Pacific does, that section 111 required the standard to be promulgated by March 19, utilities had to wait only an additional period of 84 days to know the precise form of the promulgated standard. This delay is not substantial in light of the long lead times required to build a utility boiler, and in light of the fact that the pollution control techniques required to comply with the promulgated standard are substantially the same as those required by the proposed standard.

Sierra Pacific's proposal that the applicability date be shifted to the date of promulgation is also inconsistent with Congress' clear desire that the revised standard take effect promptly. See section 111(b)(6).

In conclusion, Sierra Pacific has submitted no new information, has not shown that it has been prejudiced in any way, and has simply presented an argument that is incorrect as a matter of law. Its objection is therefore not of central relevance and its petition is denied.

[2] In any event, in the Administrator's view the 90-day requirement in section 111(b)(1)(B) no longer governs the promulgation or revision of new source standards. It has been replaced by procedures set forth in section 111(f) enacted by the 1977 amendments.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1370-5]

Standards of Performance for New Stationary Sources; Petroleum Liquid Storage Vessels

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: This regulation establishes equipment standards which limit emissions of volatile organic compounds (VOC) from new, modified or reconstructed petroleum liquid storage vessels. The standards implement the Clean Air Act and are based on the Administrator's determination that emissions from petroleum liquid storage vessels contribute significantly to air pollution. The intended effect of this regulation is to require new, modified or reconstructed petroleum liquid storage vessels to use the best demonstrated system of continuous emission reduction considering costs and nonair quality health, environmental and energy impacts.

EFFECTIVE DATE: April 4, 1980.

ADDRESSES: Docket No. OAQPS-78-2, containing all supporting information used by EPA in developing the standards, is available for public inspection and copying between 8 a.m. and 4 p.m., Monday through Friday, at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Don R. Goodwin, Director, Emission Standards and Engineering Divison (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone no. (919) 541-5271.

SUPPLEMENTARY INFORMATION:

The Standards

The standards promulgated under Subpart Ka require each new, modified or reconstructed petroleum liquid storage vessel of greater than 151,416 liters (40,000 gallons) capacity containing a petroleum liquid with a true vapor pressure greater than 10.3 kPa (1.5 psia) to be equipped with one of the following:

1. An external floating roof fitted with a double seal system between the tank wall and the floating roof;
2. A fixed roof with an internal-floating cover equipped with a seal between the tank wall and the edge of the cover;
3. A vapor recovery and disposal or return system which reduces VOC emissions by at least 95 percent, by weight; or
4. Any system which is demonstrated to the Administrator to be equivalent to those described above.

Each affected vessel storing a petroleum liquid with a true vapor pressure greater than 76.6 kPa (11.1 psia) must be equipped with a vapor recovery and disposal or return system, or equivalent. Storage vessels of less than 1,589,800 liters (420,000 gallons) capacity used for petroleum or condensate stored prior to custody transfer are exempt from the standards.

Many of the petroleum liquid storage vessels covered by the standards are likely to be in locations other than petroleum refineries. If the storage vessel contains petroleum or condensate, or finished or intermediate products manufactured at a petroleum refinery, and the size and true vapor pressure applicability criteria are met, the vessel would be covered by the standards regardless of its location. For example, cyclohexane may be produced at a petroleum refinery and then stored at a chemical plant before being used in the plant. The storage vessel at the chemical plant would be covered by the standards if its size and the true vapor pressure of the cyclohexane are greater than the cut-offs in the standards.

The regulation contains allowable seal gap criteria based on gap surface area per unit of storage vessel diameter. The standards require owners or operators to measure and report seal gaps annually for the secondary seal and every five years for the primary seal for each affected storage vessel. The standards also require owners or operators to monitor and maintain records of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of the petroleum liquid during its storage period for each affected storage vessel.

Several definitions and the monitoring and record keeping requirements of Subpart K have been revised to make them consistent with those in Subpart Ka. These revisions to Subpart K clarify the regulation and make it less burdensome for owners and operators but do not affect the emission reductions required by Subpart K.

The promulgated standards are in terms of equipment specifications and maintenance requirements rather than mass emission rates. It is extremely difficult to quantify mass emission rates for petroleum liquid storage vessels because of the varying loss mechanisms and the number of variables affecting loss rate. Section 111(h)(1) of the Act provides that equipment standards may be established for a source category if it is not feasible to prescribe or enforce a standard which specifies an emission limitation.

Environmental and Economic Impact

Compliance with these standards will reduce VOC emissions to the atmosphere from petroleum liquid storage vessels with external floating roofs by about 75 percent. This estimate is based on a comparison of VOC emissions between storage vessels equipped with external floating roofs and single seals and storage vessels equipped with any of the systems required in the standards. The standards will reduce VOC emissions by about 4,545 megagrams per year (5000 tons per year) by 1985.

This emission reduction will be realized without adverse impacts on other aspects of environmental quality, such as solid waste disposal, water pollution, or noise. There will be no adverse energy impacts associated with the standards. In fact, energy savings will result because the standards will help prevent the loss of valuable petroleum products. The economic impact of the standards is considered reasonable. The cost of complying with the standards will be only the incremental cost of installing a secondary seal. This will increase the cost of a new 61-meter diameter storage vessel by about 0.6 to 1.3 percent. The incremental capital costs will be about $12,000 to $19,000, and the average incremental annualized costs will vary between $1,100 and $3,300 per storage vessel depending on the true vapor pressure of the petroleum liquid, the average wind velocity, and the cost of the petroleum liquid.

Public Participation

The Standards were proposed in the Federal Register on May 18, 1978 (43 FR 21615). To provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standards, a public hearing was held on June 7, 1978, in Washington, D.C. In addition, during the public comment period from May 18, 1978, to July 19, 1978, a total of 35 comment letters was received. These comments have been carefully considered and, where determined to be appropriate, changes have been made in the final regulation.

Significant Comments and Changes Made

Comments were received from industry representatives, utility companies, and State and Federal agencies. Most of the comment letters contained multiple comments. The comments have been divided into the following areas for discussion: testing and monitoring, technology, impacts, and general.

Testing and Monitoring

Most of the comments concerned the proposed requirements for inspecting the seals on external floating roof storage vessels. The proposed standards required that inspection of the seals be performed while the roof was floating. They also required, however, that the secondary seal be kept in place at all times if the storage vessel contained a petroleum liquid with true vapor pressure greater than 10.3 kPa (1.5 psia). This meant that if the secondary seal would have to be dislodged or removed to inspect the primary seal, the vessel would have to be empted of petroleum liquid and the roof raised with some other liquid. The preamble suggested using water to do this. Commenters pointed out that the use of a liquid other than a petroleum liquid would put the storage vessel out of service for an indefinite period, that water was unavailable in many areas, and that water, if used, would become contaminated with petroleum liquids which would have to be separated prior to discharge.

EPA has determined that these comments are valid and that the VOC emissions occurring during the relatively short inspection period would be insignificant when compared to the impact of using water as the test fluid. Therefore, the final regulation allows the removal of the secondary seal for the inspection of the primary seal while the storage vessel is in operation. Higher emissions will, however, result from the removal of the secondary seal. To reduce this period of increased emissions, the final standards require inspection of the primary seal to be performed as rapidly as possible and the secondary seal replaced as soon as possible.

Many commenters stated that seal gap measurement at one level would provide sufficient indication of seal integrity and that the proposed requirement for measuring at eight levels would be too burdensome, expensive, and would provide little, if any, additional information. Most of these commenters recommended measuring seal gaps at the "as found" level. It is not clear whether the benefits of the eight-level gap measurement would outweigh the adverse impacts. In addition, since the final standards allow removal of the secondary seal during measurement and inspection of the primary seal, it is important to minimize the amount of time the secondary seal is not in place. Reducing the number of required measurement levels thus will help to minimize the VOC emissions during primary seal gap measurements. Therefore, the final regulation requires that seal gaps be measured at one level with the stipulation that the roof be floating off the roof leg supports. The owner or operator is required to notify EPA prior to gap measurement and provide all of the results of such measurements to EPA each time they are performed.

The proposed seal gap measurement frequency of five years was criticized by many commenters. Some claimed this to be too frequent while two commenters suggested performing gap measurements during scheduled storage vessel maintenance periods. Requiring seal gap measurements only during scheduled maintenance would not provide uniform impacts on owners and operators. Those with more frequent maintenance periods would be required to measure seal gaps more often than those with less frequent maintenance periods. Therefore the same measurement frequency is required of all owners and operators regardless of their maintenance schedules. The promulgated standards require a different frequency, however, for the primary seal than for the secondary seal. Data derived from tests conducted by Chicago Bridge and Iron Company (CBI) on a 20-foot diameter test storage vessel clearly indicate that secondary seal gaps increase VOC emissions to a greater degree than gaps in the primary seal. Because of its greater sensitivity, a more frequent inspection of the secondary seal is considered necessary. Consequently, the final regulation requires the secondary seal gaps to be measured at initial fill and at least once annually and the primary seal gaps at initial fill and at least once every five years. The requirement for more frequent gap measurements for secondary seals is not expected to increase the impact of the final standards in comparison to the proposed standards. In fact, the impact will be less because gap measurements are required at only one roof level instead of the proposed eight levels, and they may be conducted without taking the storage vessel out of service. If a storage vessel is out of service (i.e., empty) for more than one year, gap measurements must be conducted upon refilling. This is considered necessary to ensure that the seal system integrity has not severely deteriorated during the period of inactivity. The final regulation therefore, defines such refilling as "initial fill" and the required frequency of gap measurements would be based upon the date of refilling.

One commenter suggested requiring visual seal inspections instead of seal gap measurements. This approach was considered but rejected because of the inability to develop a visual inspection procedure which could be applied uniformly. The subjectiveness of such a procedure would preclude the use of the data that would be obtained.

The gap criteria by size classes specified in the proposed regulation were unfair, claimed two commenters, and are not consistent with the CBI data. As pointed out by one commenter, a three-sixteenths inch gap around the entire storage vessel would produce less gap surface area than the proposed standards allowed yet would be out of compliance with the proposed gap criteria. To eliminate this possibility, the final regulation specifies total gap surface area criteria specific to the storage vessel diameter for the primary and the secondary seal. Since the seal gap surface area allowed in the final standards is approximately equal to that allowed in the proposed standards, about the same VOC emission reduction and cost of performing gap measurements will result. The final standards, however, will provide a more effective and uniform procedure for ensuring that seals are properly installed and maintained.

Two commenters questioned the apparently inflexible requirement in the proposal that only pre-sized probes were to be used for gap measurements. As pointed out by one commenter, use of an L-shaped probe, in some cases, could eliminate the need to remove the secondary seal when measuring gaps in the primary seal. The secondary seal, in many cases, could merely be pulled back and the L-shaped probe inserted for accurate gap determinations. Such an approach may be reasonable, and there may be other suitable methods for measuring gaps. Therefore, the regulation specifies one method of gap measurement but includes provisions for allowing other methods provided they can be demonstrated to be equivalent.

According to four commenters, the monitoring requirements specified in the proposed rule were too burdensome and were probably of little value. They also pointed out problems with Reid vapor pressure conversions and true vapor pressure determinations in some cases.

EPA agreed with this comment and has re-evaluated the amount of monitoring information needed to be able to ensure that owners or operators of storage vessels covered by the regulation are complying with the standards. As a result, the final regulation has been revised to require that a record be kept of the maximum true vapor pressure and the periods of storage of each vessel's contents. This maximum true vapor pressure can be determined from available data on the typical Reid vapor pressure and the maximum expected storage temperature. This precludes the proposed requirement that an average temperature record be kept. For any crude oil with a true vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended methods, the true vapor pressure is to be determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia). The final regulation allows two exemptions from the monitoring requirements: (1) If the petroleum liquid has a Reid vapor pressure less than 6.9 kPa (1.0 psia) and the true vapor pressure will never exceed 6.9 kPa (1.0 psia) or (2) if the storage vessel is equipped with a vapor return or disposal system in accordance with the requirements of the standard. This revision relieves much of the record keeping and monitoring burden of the proposed regulation but is not expected to impact the amount of VOC emissions.

Two letters commented on the requirement in the proposed standard that there be four access points through the secondary seal to the primary seal to allow inspection while the storage vessel is in operation. One commenter said it was unnecessary while the other commenter stated that the access points should be chosen at random by the inspector. Since the regulation has been revised to allow removal of the secondary seal for primary seal inspections and gap measurements while the vessel is in operation, requiring the owner or operator to provide four access points to the primary seal is not necessary. Therefore, this requirement has been deleted.

Technology

Seven commenters questioned the validity of scaling up the CBI test vessel data by linear extrapolation to field size storage vessels as was done to calculate actual emission reductions. Many of these commenters also believed that the static test conditions were not representative of dynamic field conditions. These commenters recommended awaiting results of the American Petroleum Institute (API) study of VOC emissions from petroleum liquid storage vessels in actual field conditions. Preliminary results of the API study have been released, however, and indicate that VOC emissions from field storage vessels are directly proportional to vessel diameter. Therefore, the VOC emission estimates based on CBI data are considered valid.

Four commenters stated that storage vessels could not meet seal gap specifications even if they met current plumbness and roundness specifications contained in API Standard 650 which is used for construction standards for new storage vessels. The out-of-plumbness specification in API Standard 650 allows ½ percent of the height of the vessel and the roundness specification is grouped by vessel diameter as follows:

Storage Vessel Diameter and Radius Tolerance

	Inches
0 to 40 feet exclusive	±½
40 to 150 feet exclusive	±¾
150 to 250 feet exclusive	±1
250 feet and over	±1¼

Some of these commenters felt that the construction tolerances would have to be reduced considerably for primary and secondary seals to maintain compliance with the gap criteria at all roof levels, thereby effecting a significant economic impact of increased construction costs which EPA failed to consider. However, a compilation by EPA of the California Air Resources Board (CARB) petroleum liquid storage vessel inspection reports showed that a majority of existing welded vessels inspected in California would have been in compliance with the seal gap criteria in both the proposed and final regulations had these regulations been in effect. Since the majority of those tanks were found to be in compliance with the seal gap standards, it is EPA's judgement that all new petroleum liquid storage vessel seals could meet the gap standards. Therefore, EPA believes the standards are attainable under present construction standards.

In the proposed regulation, the requirement that a vapor recovery and return or disposal system be capable of collecting and preventing the release of all VOC vapors implied 100 percent control efficiency, and four commenters stated that this was impossible to achieve. EPA did not intend to necessarily require 100 percent control but rather to require that the system be properly designed, installed, and operated. There are two parts to a vapor recovery and return or disposal system. The vapor recovery portion collects the VOC vapors and gases from the storage vessel and vents them to a control device which then processes them by either recovering them as product or disposing of them. A properly designed collection system would be capable of collecting all the VOC vapors and gases except when pressure relief vents on the storage vessel roof would open and release VOC emissions to the atmosphere. The only time these vents would open is during periods when the emission control system is not operating properly and VOC vapors are not being vented to the control device, causing a pressure buildup in the storage vessel. Such an occurrence would be considered a malfunction if it could not be avoided through proper operation and maintenance and, therefore, would not cause the storage vessel to be out of compliance with the standard. Therefore, EPA considers the requirement that the system "collect all the vapors and gases discharged from the storage vessel" to be achievable and reasonable and has retained it in the final regulation. EPA agrees with the commenters that the second part of the system, the return or disposal portion, is not likely to be able to achieve 100 percent control efficiency. It is generally acknowledged, however, that greater than 95 percent VOC emission reduction can be achieved by at least two commonly used types of vapor control devices, thermal oxidation and carbon adsorption. Therefore, the final regulation requires that any vapor recovery and return or disposal system used to comply with the standard must collect all the VOC vapors and gases discharged from the storage vessel and be capable of processing them so as to reduce their emission to the atmosphere by at least 95 percent by weight.

To enable EPA to determine compliance with the requirements for vapor recovery and return or disposal systems, the regulation requires the owner or operator to submit plans and specifications for the system to EPA on or before the date on which construction of the storage vessel is commenced. Owners and operators are encouraged to provide this information as far in advance as possible of commencing construction.

One commenter suggested that the section on "Equivalent Equipment" be expanded to include the use of innovative vapor control equipment other than the three types specified in the proposed standards. To encourage innovation, an equivalency clause is provided in the final regulation that applies to all parts of the standards provided no decrease in emission

reduction will result and can be so demonstrated. Determinations of equivalency for VOC emission reduction systems not specifically mentioned in the regulation will generally be made by comparing the VOC emissions from such a source to the VOC emissions calculated for an external floating roof welded storage vessel with secondary and primary seals according to equations in API Bulletin 2517, "Evaporation Loss from External Floating Roof Tanks," February 1980. There will probably be cases in which determinations of equivalency cannot be made through a strict comparison of emission reduction, and these will be based on sound engineering judgment. Therefore, the regulation requires that any request for an equivalency determination be accompanied by VOC emission reduction data, if available, and also by detailed equipment and procedural specifications which would enable a sound engineering judgment to be made. In accordance with section 111(h)(3) of the Clean Air Act, any equivalency determination shall be preceded by a notice in the **Federal Register** and an opportunity for a public hearing.

Non-metallic, resilient primary seals were considered by four commenters to be equivalent to metallic shoe seals. A reevaluation of available data, some of which were received after issuance of the proposed regulation, indicates that various types of seals may provide essentially the same degree of emission reduction. The final regulation, therefore, allows use of liquid-mounted, foam-filled seals; liquid-mounted, liquid-filled seals; or vapor-mounted, foam-filled seals in addition to metallic shoe seals as primary seals on external floating roofs. Vapor-mounted seals, however, are equivalent to the others only when the gap area of vapor-mounted seals is significantly less than the gap area of the others. Therefore, the final regulation requires more stringent gap criteria for vapor-mounted primary seals.

Several commenters recommended exemption from the standards for storage vessels involved in oil field and production operations. Such vessels are generally small, bolted, and equipped with fixed roofs. This is to enable them to be dismantled, transported and reerected as needed. Therefore, to comply with the standards, a new production field vessel would have to be equipped with either an internal floating roof or a vapor recovery system. Commenters provided information which indicated that vapor recovery would be very difficult and expensive due to the remote location of many vessels. One commenter also submitted data to show that internal floating roofs would generally not be cost-effective for production vessels with capacities less than 1,589,873 liters (420,000 gallons). Therefore, the final regulation exempts each storage vessel with a capacity of less than 1,589,873 liters (420,000 gallons) used for petroleum or condensate stored, processed, or treated prior to custody transfer. This exemption applies to storage between the time that the petroleum liquid is removed from the ground and the time that custody of the petroleum liquid is transferred from the well or producing operations to the transportation operations. If it is determined in the future that VOC emissions from new production field vessels smaller than 1,589,873 liters (420,000 gallons) are significant, separate standards of performance will be developed.

One commenter indicated that internal non-contact floating roofs do not reduce emissions to the same degree as contact floating roofs and points out that API Standard 650 recommends the use of the contact type. EPA is concerned about the difference in emission control of these two types of floating roofs although insufficient data exist at present to justify a revision to the standards for petroleum liquid storage vessels. One type of non-contact floating roof was tested at CBI and the results were forwarded to EPA in late 1978. The results indicate that the roof did not reduce emissions to the same degree as a contact roof. However, slight auxiliary equipment differences such as different seals used with the different roofs prohibit development of valid conclusions. Therefore, more information is necessary to determine if the petroleum liquid storage vessels standard should be revised. Consequently, EPA is considering a study specifically to determine differences in VOC emission control of these two types of internal floating roofs.

Impacts

The proposed regulation specified that the roof must be floating on the liquid at all times except when the storage vessel is completely emptied, during initial fill, or performance tests. Three commenters stated that the level of the liquid should be allowed to go below the level where the roof comes to rest on the roof leg supports even if the vessel is not completely emptied. This would avoid the loss of working capacity and, thus, the need for more storage vessels. A significant amount of VOC emissions, however, would result upon refilling. The intent of the regulation is to avoid having a vapor space between the roof and the petroleum liquid surface for extended periods. The quantity of petroleum liquid remaining in the bottom of a storage vessel with the floating roof on its leg supports and the time it remains in this condition determines the amount of VOC saturation of the vapor space and the subsequent emissions upon refilling the storage vessel. It is therefore considered beneficial to the environment for the roof to be kept floating at all times except when the tank is initially filled or completely emptied and refilled for such purposes as routine tank maintenance, inspections, petroleum liquid deliveries, or transfer operations. Therefore, the final regulation requires that the roof be floating on the liquid at all times except during initial fill and when the vessel is completely emptied and refilled. To minimize the amount of time the petroleum liquid remains in the storage vessel while the roof is resting on the roof leg supports, the final regulation also requires that the process of emptying and refilling be performed as rapidly as possible.

As mentioned before, the proposed regulation did not require the roof to be floating on the petroleum liquid during performance tests. This exemption was needed since the proposal required that gap measurements be conducted with a liquid other than a petroleum liquid in the storage vessel (the preamble suggested using water). Therefore, the storage vessel would have had to be emptied and the roof re-floated on the non-petroleum liquid. Since the final regulation allows gap measurements to be conducted while the vessel contains petroleum liquid, this exemption has been removed.

General

It was pointed out by two commenters that because the proposed regulation stated that a secondary seal gap would exist only if the probe touched the primary seal, gaps in the same location in the primary seal and the secondary seal would not be allowed. The proposed regulation stated that "a gap is deemed to exist under the following conditions: * * * for a secondary seal, the probe is to touch the primary seal without forcing." This erroneously implied that a secondary seal gap would not exist should the probe be able to pass between the secondary and primary seals and the tank wall and touch the liquid surface. These commenters concluded that EPA intended to regulate not only the size and area of seal gaps but also their locations in each seal. This was not the

intent of the proposed regulation. The final regulation eliminates this ambiguity and redefines "gaps" as those places where a uniform one-eighth inch diameter probe passes freely between the seal and the tank wall.

Two commenters stated that a person walking on an external floating roof could alter gap configuration and would pose a safety hazard because the roof could possibly sink. Three commenters felt that a fire hazard would be created by the vapor that would become trapped between the primary and secondary seals. These comments were expressed as opinions without any supporting data or information. Since no such incidents have been reported to EPA, and since external floating roofs with double seals are commonly used and apparently operating safely even during inspections, it is EPA's judgement that the standards will not create either of these hazards. A person walking on an external floating roof should not cause significant gap alterations since these roofs are designed and built for this purpose. Any small gap alteration should not affect compliance status of seal gaps since the allowable gap criteria are based on total surface area of all gaps.

The term "hydrocarbon" has been changed to "volatile organic compounds (VOC)" in the final regulation. This change in terminology is consistent with current EPA policy concerning compounds which react photochemically in the atmosphere to form ozone. Reference has been made in the past to "organic solvents," "thinners," and "hydrocarbons," in addition to "VOC" to represent these compounds. Some organics which are ozone precursors are not hydrocarbons in the strictest definition and are not always used as solvents. Therefore, all reference to emissions and emission reduction in the standards refer to the organic compounds which are ozone precursors and have been designated VOC.

Docket

The docket is an organized and complete file of all the information submitted to or otherwise considered by the Administrator in the development of this rulemaking. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process. Along with the statement of basis and purpose of the promulgated rule and EPA responses to significant comments, the contents of the docket will serve as the record in case of judicial review.

Miscellaneous

The effective date of this regulation is April 4, 1980. Section 111 of the Clean Air Act provides that standards of performance become effective upon promulgation and apply to affected facilities, construction or modification of which was commenced after the date of proposal (May 18, 1978).

EPA will review this regulation four years from the date of promulgation. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, and improvements in emission control technology.

It should be noted that standards of performance for new stationary sources established under section 111 of the Clean Air Act reflect:

> * * * Application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any non air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated (section 111(a)(1)).

Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act requries (or has the potential for requiring) the imposition of a more stringent emission standard in several situations.

For example, applicable costs do not play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources locating in nonattainment areas, i.e., those areas where statutorily-mandated health and welfare standards are being violated. In this respect, section 173 of the Act requires that a new or modified source constructed in an area which exceeds the National Ambient Air Quality Standard (NAAQS) must reduce emissions to the level which reflects the "lowest achievable emission rate" (LAER), as defined in section 171(3), for such category of source. The statute defines LAER as that rate of emissions based on the following, whichever is more stringent:

> (A) The most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or
>
> (B) The most stringent emission limitation which is achieved in practice by such class or category of source.

In no event can the emission rate exceed any applicable new source performance standard (section 171(3)).

A similar situation may arise under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require that certain sources [referred to in section 169(1)] employ "best available control technology" (BACT) as defined in section 169(3) for all pollutants regulated under the Act. Best available control technology must be determined on a case-by-case basis, taking energy, environmental and economic impacts, and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the Act.

In all events, State implementation plans (SIP's) approved or promulgated under section 110 of the Act must provide for the attainment and maintenance of National Ambient Air Quality Standards designed to protect public health and welfare. For this purpose, SIP's must in some cases require greater emission reductions than those required by standards of performance for new sources.

Finally, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for revisions of standards of performance which the Administrator determines to be substantial. An economic impact assessment has been prepared and is included in the docket. All the information in the economic impact assessment was considered in determining the cost of these standards.

Dated: March 28, 1980.

Douglas M. Costle,

Administrator.

40 CFR Part 60 is amended by revising § 60.11(a); the heading of Subpart K; § 60.110(c)(1) and (c)(2); § 60.111(b) and (c); the heading of § 60.112; § 60.113; and by adding a new Subpart Ka as follows:

1. Paragraph (a) of § 60.11 is revised to read as follows:

§ 60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined only by performance tests established by § 60.8, unless otherwise specified in the applicable standard.

* * * * *

2. The heading for subpart K is revised to read as follows:

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids Constructed After June 11, 1973 and Prior to May 19, 1978

3. Paragraphs (c)(1) and (c)(2) of § 60.110 of Subpart K are revised to read as follows:

§ 60.110 Applicability and designation of affected facility.

* * * * *

(c) * * *

(1) Has a capacity greater than 151,416 liters (40,000 gallons), but not exceeding 246,052 liters (65,000 gallons), and commences construction or modification after March 8, 1974, and prior to May 19, 1978.

(2) Has a capacity greater than 246,052 liters (65,000 gallons) and commences construction or modification after June 11, 1973, and prior to May 19, 1978.

* * * * *

4. Paragraphs (b) and (c) of § 60.111 of Subpart K are revised to read as follows:

§ 60.111 Definitions.

* * * * *

(b) "Petroleum liquids" means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Nos. 2 through 6 fuel oils as specified in ASTM-D-396-78, gas turbine fuel oils Nos. 2-GT through 4-GT as specified in ASTM-D-2880-78, or diesel fuel oils Nos. 2-D and 4-D as specified in ASTM-D-97578.

(c) "Petroleum refinery" means each facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, extracting, or reforming of unfinished petroleum derivatives.

* * * * *

5. The heading of § 60.112 of Subpart K is revised to read as follows:

§ 60.112 Standard for volatile organic compounds (VOC).

* * * * *

6. Section 60.113 of Subpart K is revised to read as follows:

§ 60.113 Monitoring of operations.

(a) Except as provided in paragraph (d) of this section, the owner or operator subject to this subpart shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.

(b) Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(c) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).

(d) The following are exempt from the requirements of this section:

(1) Each owner or operator of each affected facility which stores petroleum liquids with a Reid vapor pressure of less than 6.9 kPa (1.0 psia) provided the maximum true vapor pressure does not exceed 6.9 kPa (1.0 psia).

(2) Each owner or operator of each affected facility equipped with a vapor recovery and return or disposal system in accordance with the requirements of § 60.112.

7. A new Subpart Ka is added to read as follows:

Subpart Ka—Standards of Performance for Storage vessels for Petroleum Liquids Constructed After May 18, 1978

Sec.

60.110a Applicability and designation of affected facility.
60.111a Definitions.
60.112a Standard for volatile organic compounds (VOC).
60.113a Testing and procedures.
60.114a Equivalent equipment and procedures.
60.115a Monitoring of operations.

Authority: Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

§ 60.110a Applicability and designation of affected facility.

(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,416 liters (40,000 gallons) and for which construction is commenced after May 18, 1978.

(b) Each petroleum liquid storage vessel with a capacity of less than 1,589,873 liters (420,000 gallons) used for petroleum or condensate stored, processed, or treated prior to custody transfer is not an affected facility and, therefore, is exempt from the requirements of this subpart.

§ 60.111a Definitions.

In addition to the terms and their definitions listed in the Act and Subpart A of this part the following definitions apply in this subpart:

(a) "Storage vessel" means each tank, reservoir, or container used for the storage of petroleum liquids, but does not include:

(1) Pressure vessels which are designed to operate in excess of 204.9 kPa (15 psig) without emissions to the atmosphere except under emergency conditions.

(2) Subsurface caverns or porous rock reservoirs, or

(3) Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.

(b) "Petroleum liquids" means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Nos. 2 through 6 fuel oils as specified in ASTM-D-396-78, gas turbine fuel oils Nos. 2-GT through 4-GT as specified in ASTM-D-2880-78, or diesel fuel oils Nos. 2-D and 4-D as specified in ASTM-D-975-78.

(c) "Petroleum refinery" means each facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, extracting, or reforming of unfinished petroleum derivatives.

(d) "Petroleum" means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

(e) "Condensate" means hydrocarbon liquid separated from natural gas which condenses due to changes in the

temperature or pressure, or both, and remains liquid at standard conditions.

(f) "True vapor pressure" means the equilibrium partial pressure exerted by a petroleum liquid such as determined in accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss from Floating Roof Tanks, 1962.

(g) "Reid vapor pressure" is the absolute vapor pressure of volatile crude oil and volatile non-viscous petroleum liquids, except liquified petroleum gases, as determined by ASTM-D-323-58 (reapproved 1968).

(h) "Liquid-mounted seal" means a foam or liquid-filled primary seal mounted in contact with the liquid between the tank wall and the floating roof continuously around the circumference of the tank.

(i) "Metallic shoe seal" includes but is not limited to a metal sheet held vertically against the tank wall by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(j) "Vapor-mounted seal" means a foam-filled primary seal mounted continuously around the circumference of the tank so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the tank wall, the liquid surface, and the floating roof.

(k) "Custody transfer" means the transfer of produced petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.

§ 60.112a Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel to which this subpart applies which contains a petroleum liquid which, as stored, has a true vapor pressure equal to or greater than 10.3 kPa (1.5 psia) but not greater than 76.6 kPa (11.1 psia) shall equip the storage vessel with one of the following:

(1) An external floating roof, consisting of a pontoon-type or double-deck-type cover that rests on the surface of the liquid contents and is equipped with a closure device between the tank wall and the roof edge. Except as provided in paragraph (a)(1)(ii)(D) of this section, the closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal and the upper seal is referred to as the secondary seal. The roof is to be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(i) The primary seal is to be either a metallic shoe seal, a liquid-mounted seal, or a vapor-mounted seal. Each seal is to meet the following requirements:

(A) The accumulated area of gaps between the tank wall and the metallic shoe seal or the liquid-mounted seal shall not exceed 212 cm^2 per meter of tank diameter (10.0 in^2 per ft of tank diameter) and the width of any portion of any gap shall not exceed 3.81 cm (1½ in).

(B) The accumulated area of gaps between the tank wall and the vapor-mounted seal shall not exceed 21.2 cm^2 per meter of tank diameter (1.0 in^2 per ft of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (½ in).

(C) One end of the metallic shoe is to extend into the stored liquid and the other end is to extend a minimum vertical distance of 61 cm (24 in) above the stored liquid surface.

(D) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (a)(1)(ii)(B) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2 cm^2 per meter of tank diameter (1.0 in^2 per ft of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (½ in).

(C) There are to be no holes, tears or other openings in the seal or seal fabric.

(D) The owner or operator is exempted from the requirements for secondary seals and the secondary seal gap criteria when performing gap measurements or inspections of the primary seal.

(iii) Each opening in the roof except for automatic bleeder vents and rim space vents is to provide a projection below the liquid surface. Each opening in the roof except for automatic bleeder vents, rim space vents and leg sleeves is to be equipped with a cover, seal or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use or as described in pargraph (a)(1)(iv) of this section. Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting.

(iv) Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(2) A fixed roof with an internal floating type cover equipped with a continuous closure device between the tank wall and the cover edge. The cover is to be floating at all times, (i.e., off the leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the cover is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible. Each opening in the cover except for automatic bleeder vents and the rim space vents is to provide a projection below the liquid surface. Each opening in the cover except for automatic bleeder vents, rim space vents, stub drains and leg sleeves is to be equipped with a cover, seal, or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the cover is floating except when the cover is being floated off or is being landed on the leg supports. Rim vents are to be set to open only when the cover is being floated off the leg supports or at the manufacturer's recommended setting.

(3) A vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least 95 percent by weight.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in § 60.114a.

(b) The owner or operator of each storage vessel to which this subpart applies which contains a petroleum liquid which, as stored, has a true vapor pressure greater than 76.6 kPa (11.1 psia), shall equip the storage vessel with a vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least 95 percent by weight.

§ 60.113a Testing and procedures.

(a) Except as provided in § 60.8(b) compliance with the standard prescribed in § 60.112a shall be determined as follows or in accordance with an equivalent procedure as provided in § 60.114a.

(1) The owner or operator of each storage vessel to which this subpart applies which has an external floating roof shall meet the following requirements:

(i) Determine the gap areas and maximum gap widths between the primary seal and the tank wall, and the secondary seal and the tank wall according to the following frequency and furnish the Administrator with a written report of the results within 60 days of performance of gap measurements:

(A) For primary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every five years thereafter. All primary seal inspections or gap measurements which require the removal or dislodging of the secondary seal shall be accomplished as rapidly as possible and the secondary seal shall be replaced as soon as possible.

(B) For secondary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every year thereafter.

(C) If any storage vessel is out of service for a period of one year or more, subsequent refilling with petroleum liquid shall be considered initial fill for the purposes of paragraphs (a)(1)(i)(A) and (a)(1)(i)((B) of this section.

(ii) Determine gap widths in the primary and secondary seals individually by the following procedures:

(A) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(B) Measure seal gaps around the entire circumference of the tank in each place where a ⅛" diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the tank wall and measure the circumferential distance of each such location.

(C) The total surface area of each gap described in paragraph (a)(1)(ii)(B) of this section shall be determined by using probes of various widths to accurately measure the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(iii) Add the gap surface area of each gap location for the primary seal and the secondary seal individually. Divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the appropriate ratio in the standard in § 60.112a(a)(1)(i) and § 60.112a(a)(1)(ii).

(iv) Provide the Administrator 30 days prior notice of the gap measurement to afford the Administrator the opportunity to have an observer present.

(2) The owner or operator of each storage vessel to which this subpart applies which has a vapor recovery and return or disposal system shall provide the following information to the Administrator on or before the date on which construction of the storage vessel commences:

(i) Emission data, if available, for a similar vapor recovery and return or disposal system used on the same type of storage vessel, which can be used to determine the efficiency of the system. A complete description of the emission measurement method used must be included.

(ii) The manufacturer's design specifications and estimated emission reduction capability of the system.

(iii) The operation and maintenance plan for the system.

(iv) Any other information which will be useful to the Administrator in evaluating the effectiveness of the system in reducing VOC emissions.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))

§ 60.114a Equivalent equipment and procedures.

(a) Upon written application from an owner or operator and after notice and opportunity for public hearing, the Administrator may approve the use of equipment or procedures, or both, which have been demonstrated to his satisfaction to be equivalent in terms of reduced VOC emissions to the atmosphere to the degree prescribed for compliance with a specific paragraph(s) of this subpart.

(b) The owner or operator shall provide the following information in the application for determination of equivalency:

(1) Emission data, if available, which can be used to determine the effectiveness of the equipment or procedures in reducing VOC emissions from the storage vessel. A complete description of the emission measurement method used must be included.

(2) The manufacturer's design specifications and estimated emission reduction capability of the equipment.

(3) The operation and maintenance plan for the equipment.

(4) Any other information which will be useful to the Administrator in evaluating the effectiveness of the equipment or procedures in reducing VOC emissions.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 60.115a Monitoring of operations.

(a) Except as provided in paragraph (d) of this section, the owner or operator subject to this subpart shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.

(b) Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(c) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).

(d) The following are exempt from the requirements of this section:

(1) Each owner or operator of each storage vessel storing a petroleum liquid with a Reid vapor pressure of less than 6.9 kPa (1.0 psia) provided the maximum true vapor pressure does not exceed 6.9 kPa (1.0 psia).

(2) Each owner or operator of each storage vessel equipped with a vapor recovery and return or disposal system in accordance with the requirements of §§ 60.112a(a)(3) and 60.112a(b).

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

[FR Doc. 80-10222 Filed 4-3-80; 8:45 am]
BILLING CODE 6560-01-M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL-1493-1]

Standards of Performance of New Stationary Sources: Adjustment of Opacity Standard for Fossil Fuel Fired Steam Generator

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: On April 1, 1980, there was published in the **Federal Register** (45 FR 21302) a notice of proposed rulemaking setting forth a proposed EPA adjustment of the capacity standard for Interstate Power Company's Lansing Unit No. 4, in Lansing, Iowa. The proposal was based on Interstate's demonstration of the conditions that entitle it to such an adjustment under 40 CFR 60.11(e). Interested persons were given thirty days in which to submit comments on the proposed rulemaking.

No written comments have been received and the proposed adjustment is approved without change and is set forth below.

Effective Date: May 29, 1980.

FOR FURTHER INFORMATION CONTACT: Henry Rompage, Enforcement Division, EPA, Region VII, Area Code 816-374-3171.

Signed at Washington, D.C., on May 22, 1980.

Douglas M. Costle,

Administrator.

In consideration of the foregoing, Part 60 of 40 CFR Chapter I is amended as follows:

Subpart D—Standards of Performance for Fossil Fuel-Fired Generators

§ 60.42 [Amended]

1. Section 60.42 is amended by adding paragraph (b)(2):

* * * * *

(b) * * *

(2) Interstate Power Company shall not cause to be discharged into the atmosphere from its Lansing Station Unit No. 1 in Lansing, Iowa, any gases which exhibit greater than 32% opacity, except that a maximum of 39% opacity shall be permitted for not more than six minutes in any hour.

(Sec. 111.301(a), Clear Air Act as amended (42 U.S.C. 7411, 7601)).

2. Section 60.45(g)(1) is amended by adding Paragraph (ii) as follows:

§ 60.45 Emission and fuel monitoring.

* * * * *

(g) * * *

(1) * * *

(i) * * *

(ii) For sources subject to the opacity standard of § 60.42(b)(2), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 32 percent opacity, except that one six-minute average per hour of up to 39 percent opacity need not be reported.

[FR Doc. 80-16409 Filed 5-28-80, 8:45 am]

BILLING CODE 6560-01-M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1458-4]

Standards of Performance for New Stationary Sources; Revised Reference Methods 13A and 13B

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This rule revises Appendix A, Reference Methods 13A and 13B, the detailed requirements used to measure total fluoride emissions to determine whether affected facilities at phosphate fertilizer and primary aluminum plants are in compliance with the standard of performance. Since the methods were originally promulgated on January 26, 1976, several revisions that would clarify, correct, and improve the methods have been evaluated. Adoption of these revisions will make Methods 13A and 13B more accurate and reliable.

EFFECTIVE DATE: June 20, 1980.

FOR FURTHER INFORMATION CONTACT: Mr. Roger T. Shigehara, Emission Measurement Branch (MD-19), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-2237.

SUPPLEMENTARY INFORMATION: The specific changes to Methods 13A and 13B are:

1. Aluminum and silicon dioxide are no longer listed as interferences since sample distillation eliminates this problem. Grease on sample-exposed surfaces, which may adsorb F, has been added as a potential interference.

2. The heat source for the sample distillation has been changed from a hot plate to a bunsen burner.

3. The requirements for the sample train filter when it is placed between the probe and first impinger have been changed to allow any filter that can meet certain specifications. The filter (1) must withstand prolonged exposure to temperatures up to 135°C (275°F), (2) have at least 95 percent collection efficiency for 0.3 μm dioctyl phthalate smoke particles, and (3) have a low F blank value.

4. A requirement to oven dry the sodium fluoride before preparing the standardizing solution has been added.

5. Additional details have been added to clarify sample recovery procedures.

6. A requirement to collect and analyze a sample blank has been added.

7. To prevent F carryover after distillation of high concentration F samples, a procedure to remove the residual F has been added.

8. The definition of V_t has been changed to make it clearer.

9. Method 13B requires additional standardizing solutions for specific ion electrodes which do not display a linear response to low concentration F samples.

PUBLIC COMMENTS: Upon proposal of the amendments to the New Source Performance Standard for Primary Aluminum plants, a comment was received on Methods 13A and 13B. The comment noted that in some cases the sampling train may be required to collect sample continuously over a period of 24 hours. Such a large sample would exceed the capacity of the train's silica gel to absorb the residual moisture in the sample.

EPA agrees with this comment and has modified Methods 13A and 13B to eliminate this potential problem. These changes are consistent with the changes in Method 5 allowing the following options: (1) alternative systems of cooling the gas stream and measuring the condensed moisture, (2) addition of extra silica gel to the impinger train, or (3) replacement of spent silica gel during a sample run.

The Administrator finds that these amendments are minor and technical, and that they will have no effect on the stringency of the affected NSPS's. Notice and public procedure on these amendments are therefore unnecessary.

(Sections 111, 114, and 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7414, and 7601(a))

Dated: June 16, 1980.

Douglas M. Costle,

Administrator.

40 CFR Part 60 is amended by revising Methods 13A and 13B of Appendix A to read as follows:

Appendix A—Reference Test Methods

* * * * *

Method 13A. Determination of Total Fluoride Emissions From Stationary Sources; SPADNS Zirconium Lake Method

1. Applicability and Principle

1.1 Applicability. This method applies to the determination of fluoride (F) emissions from sources as specified in the regulations. It does not measure fluorocarbons, such as freons.

1.2 Principle. Gaseous and particulate F are withdrawn isokinetically from the source and collected in water and on a filter. The total F is then determined by the SPADNS Zirconium Lake colorimetric method.

2. Range and Sensitivity

The range of this method is 0 to 1.4 μg F/ml. Sensitivity has not been determined.

3. Interferences

Large quantities of chloride will interfere with the analysis, but this interference can be prevented by adding silver sulfate into the distillation flask (see Section 7.3.4). If chloride ion is present, it may be easier to use the Specific Ion Electrode Method (Method 13B). Grease on sample-exposed surfaces may cause low F results due to adsorption.

4. Precision, Accuracy, and Stability

4.1 Precision. The following estimates are based on a collaborative test done at a primary aluminum smelter. In the test, six laboratories each sampled the stack simultaneously using two sampling trains for a total of 12 samples per sampling run. Fluoride concentrations encountered during the test ranged from 0.1 to 1.4 mg F/m³. The within-laboratory and between-laboratory standard deviations, which include sampling and analysis errors, were 0.044 mg F/m³ with 60 degrees of freedom and 0.064 mg F/m³ with five degrees of freedom, respectively.

4.2 Accuracy. The collaborative test did not find any bias in the analytical method.

4.3 Stability. After the sample and colorimetric reagent are mixed, the color formed is stable for approximately 2 hours. A 3°C temperature difference between the sample and standard solutions produces an error of approximately 0.005 mg F/liter. To avoid this error, the absorbances of the sample and standard solutions must be measured at the same temperature.

5. Apparatus

5.1 Sampling Train. A schematic of the sampling train is shown in Figure 13A-1; it is similar to the Method 5 train except the filter position is interchangeable. The sampling train consists of the following components:

5.1.1 Probe Nozzle, Pitot Tube, Differential Pressure Gauge, Filter Heating System, Metering System, Barometer, and Gas Density Determination Equipment. Same as Method 5, Sections 2.1.1, 2.1.3, 2.1.4, 2.1.6, 2.1.8, 2.1.9, and 2.1.10. When moisture condensation is a problem, the filter heating system is used.

5.1.2 Probe Liner. Borosilicate glass or 316 stainless steel. When the filter is located immediately after the probe, the tester may use a probe heating system to prevent filter plugging resulting from moisture condensation, but the tester shall not allow the temperature in the probe to exceed 120±14°C (248±25°F).

5.1.3 Filter Holder. With positive seal against leakage from the outside or around the filter. If the filter is located between the probe and first impinger, use borosilicate glass or stainless steel with a 20-mesh stainless steel screen filter support and a silicone rubber gasket; do not use a glass frit or a sintered metal filter support. If the filter is located between the third and fourth impingers, the tester may use borosilicate glass with a glass frit filter support and a silicone rubber gasket. The tester may also use other materials of construction with approval from the Administrator.

5.1.4 Impingers. Four impingers connected as shown in Figure 13A-1 with ground-glass (or equivalent), vacuum-tight fittings. For the first, third, and fourth

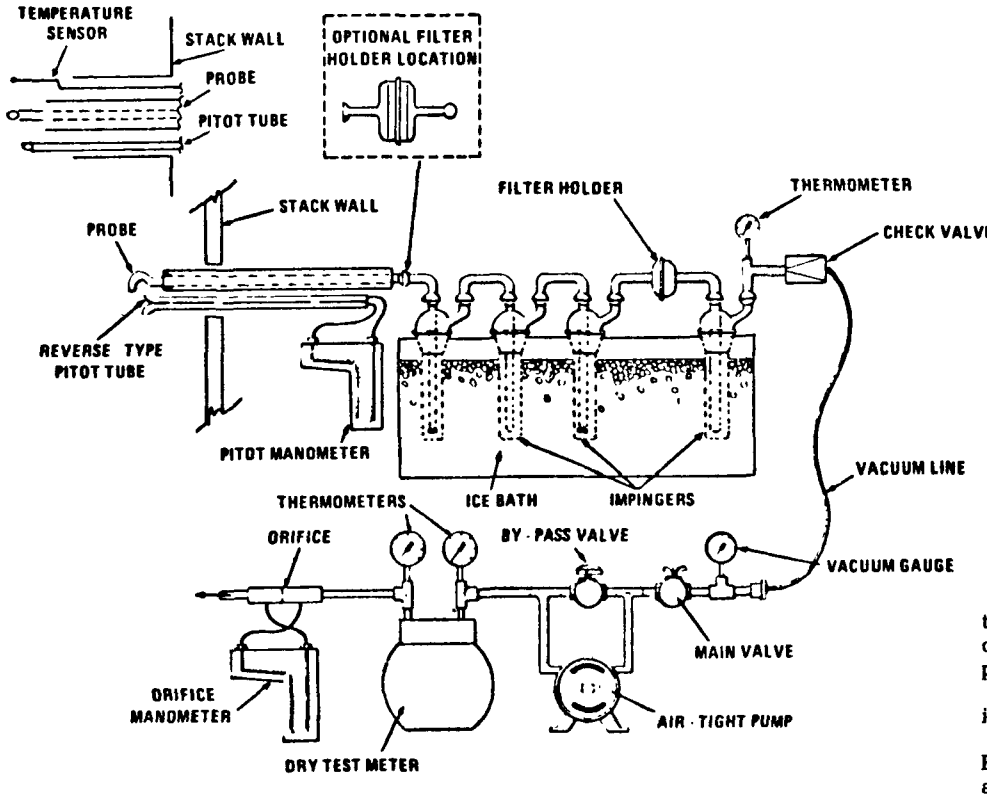


Figure 13A 1. Fluoride sampling train.

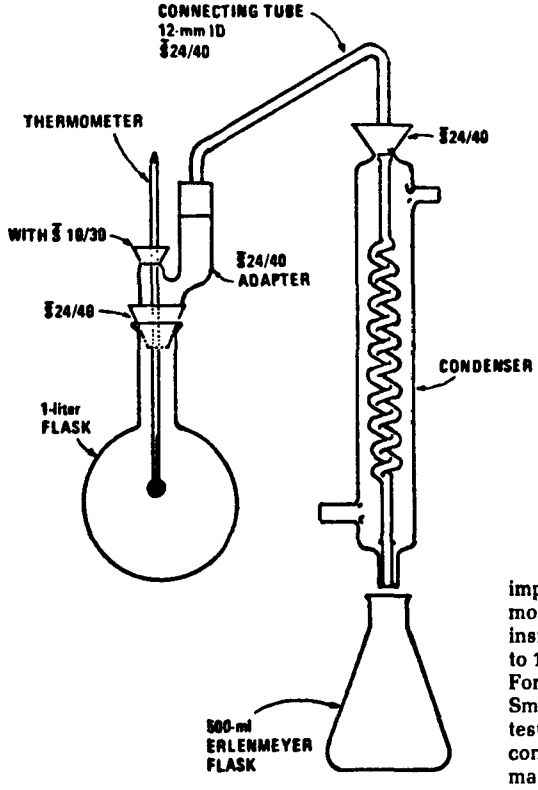


Figure 13A-2. Fluoride distillation apparatus.

impingers, use the Greenburg-Smith design, modified by replacing the tip with a 1.3-cm-inside-diameter (½ in.) glass tube extending to 1.3 cm (½ in.) from the bottom of the flask. For the second impinger, use a Greenburg-Smith impinger with the standard tip. The tester may use modifications (e.g., flexible connections between the impingers or materials other than glass), subject to the approval of the Administrator. Place a thermometer, capable of measuring temperature to within 1°C (2°F), at the outlet of the fourth impinger for monitoring purposes.

5.2 Sample Recovery. The following items are needed:

5.2.1 Probe-Liner and Probe-Nozzle Brushes, Wash Bottles, Graduated Cylinder and/or Balance, Plastic Storage Containers, Rubber Policeman, Funnel. Same as Method 5, Sections 2.2.1 to 2.2.2 and 2.2.5 to 2.2.8, respectively.

5.2.2 Sample Storage Container. Wide-mouth, high-density-polyethylene bottles for impinger water samples, 1-liter.

5.3 Analysis. The following equipment is needed:

5.3.1 Distillation Apparatus. Glass distillation apparatus assembled as shown in Figure 13A–2.

5.3.2 Bunsen Burner.

5.3.3 Electric Muffle Furnace. Capable of heating to 600°C.

5.3.4 Crucibles. Nickel, 75- to 100-ml.

5.3.5 Beakers. 500-ml and 1500-ml.

5.3.6 Volumetric Flasks. 50-ml.

5.3.7 Erlenmeyer Flasks or Plastic Bottles. 500-ml.

5.3.8 Constant Temperature Bath. Capable of maintaining a constant temperature of ±1.0°C at room temperature conditions.

5.3.9 Balance. 300-g capacity to measure to ±0.5 g.

5.3.10 Spectrophotometer. Instrument that measures absorbance at 570 nm and provides at least a 1-cm light path.

5.3.11 Spectrophotometer Cells. 1-cm pathlength.

6. Reagents

6.1 Sampling. Use ACS reagent-grade chemicals or equivalent, unless otherwise specified. The reagents used in sampling are as follows:

6.1.1 Filters.

6.1.1.1 If the filter is located between the third and fourth impingers, use a Whatman [1] No 1 filter, or equivalent, sized to fit the filter holder.

6.1.1.2 If the filter is located between the probe and first impinger, use any suitable medium (e.g., paper organic membrane) that conforms to the following specifications: (1) The filter can withstand prolonged exposure to temperatures up to 135°C (275°F). (2) The filter has at least 95 percent collection efficiency (≤5 percent penetration) for 0.3 μm dioctyl phthalate smoke particles. Conduct the filter efficiency test before the test series, using ASTM Standard Method D 2986–71, or use test data from the supplier's quality control program. (3) The filter has a low F blank value (≤0.015 mg F/cm² of filter area). Before the test series, determine the average F blank value of at least three filters (from the lot to be used for sampling) using the applicable procedures described in Sections 7.3 and 7.4 of this method. In general, glass fiber filters have high and/or variable F blank values, and will not be acceptable for use.

6.1.2 Water. Deionized distilled, to conform to ASTM Specification D 1193–74, Type 3. If high concentrations of organic matter are not expected to be present, the analyst may delete the potassium permanganate test for oxidizable organic matter.

6.1.3 Silica Gel, Crushed Ice, and Stopcock Grease. Same as Method 5, Section 3.1.2, 3.1.4, and 3.1.5, respectively.

6.2 Sample Recovery. Water, from same container as described in Section 6.1.2, is needed for sample recovery.

6.3 Sample Preparation and Analysis. The reagents needed for sample preparation and analysis are as follows:

6.3.1 Calcium Oxide (CaO). Certified grade containing 0.005 percent F or less.

6.3.2 Phenolphthalein Indicator. Dissolve 0.1 g of phenolphthalein in a mixture of 50 ml of 90 percent ethanol and 50 ml of deionized distilled water.

6.3.3 Silver Sulfate (Ag_2SO_4).

6.3.4 Sodium Hydroxide (NaOH). Pellets.

6.3.5 Sulfuric Acid (H_2SO_4), Concentrated.

6.3.6 Sulfuric Acid, 25 percent (V/V). Mix 1 part of concentrated H_2SO_4 with 3 parts of deionized distilled water.

6.3.7 Filters. Whatman No. 541, or equivalent.

6.3.8 Hydrochloric Acid (HCl), Concentrated.

6.3.9 Water. From same container as described in Section 6.1.2.

6.3.10 Fluoride Standard Solution, 0.01 mg F/ml. Dry in an oven at 110°C for at least 2 hours. Dissolve 0.2210 g of NaF in 1 liter of deionized distilled water. Dilute 100 ml of this solution to 1 liter with deionized distilled water.

6.3.11 SPADNS Solution [4, 5 dihydroxy-3-(p-sulfophenylazo)-2,7-naphthalene-disulfonic acid trisodium salt]. Dissolve 0.960 ± 0.010 g of SPADNS reagent in 500 ml deionized distilled water. If stored in a well-sealed bottle protected from the sunlight, this solution is stable for at least 1 month.

6.3.12 Spectrophotometer Zero Reference Solution. Prepare daily. Add 10 ml of SPADNS solution (6.3.11) to 100 ml deionized distilled water, and acidify with a solution prepared by diluting 7 ml of concentrated HCl to 10 ml with deionized distilled water.

6.3.13 SPADNS Mixed Reagent. Dissolve 0.135 ± 0.005 g of zirconyl chloride octahydrate ($ZrOCl_2 \cdot 8H_2O$) in 25 ml of deionized distilled water. Add 350 ml of concentrated HCl, and dilute to 500 ml with deionized distilled water. Mix equal volumes of this solution and SPADNS solution to form a single reagent. This reagent is stable for at least 2 months.

7. Procedure

7.1 Sampling. Because of the complexity of this method, testers should be trained and experienced with the text procedures to assure reliable results.

7.1.1 Pretest Preparation. Follow the general procedure given in Method 5, Section 4.1.1, except the filter need not be weighed.

7.1.2 Preliminary Determinations. Follow the general procedure given in Method 5, Section 4.1.2., except the nozzle size selected must maintain isokinetic sampling rates below 28 liters/min (1.0 cfm).

7.1.3 Preparation of Collection Train. Follow the general procedure given in Method 5, Section 4.1.3, except for the following variations:

Place 100 ml of deionized distilled water in each of the first two impingers, and leave the third impinger empty. Transfer approximately 200 to 300 g of preweighed silica gel from its container to the fourth impinger.

Assemble the train as shown in Figure 13A–1 with the filter between the third and fourth impingers. Alternatively, if a 20-mesh stainless steel screen is used for the filter support, the tester may place the filter between the probe and first impinger. The tester may also use a filter heating system to prevent moisture condensation, but shall not allow the temperature around the filter holder to exceed 120 ± 14°C (248 ± 25°F). Record the filter location on the data sheet.

7.1.4 Leak-Check Procedures. Follow the leak-check procedures given in Method 5, Sections 4.1.4.1 (Pretest Leak-Check), 4.1.4.2 (Leak-Checks During the Sample Run), and 4.1.4.3 (Post-Test Leak-Check).

7.1.5 Fluoride Train Operation. Follow the general procedure given in Method 5, Section 4.1.5, keeping the filter and probe temperatures (if applicable) at 120 ± 14°C (248 ± 25°F) and isokinetic sampling rates below 28 liters/min (1.0 cfm). For each run, record the data required on a data sheet such as the one shown in Method 5, Figure 5–2.

7.2 Sample Recovery. Begin proper cleanup procedure as soon as the probe is removed from the stack at the end of the sampling period.

Allow the probe to cool. When it can be safely handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it to keep from losing part of the sample. Do not cap off the probe tip tightly while the sampling train is cooling down, because a vacuum would form in the filter holder, thus drawing impinger water backward.

Before moving the sample train to the cleanup site, remove the probe from the sample train, wipe off the silicone grease, and cap the open outlet of the probe. Be careful not to lose any condensate, if present. Remove the filter assembly, wipe off the silicone grease from the filter holder inlet, and cap this inlet. Remove the umbilical cord from the last impinger, and cap the impinger. After wiping off the silicone grease, cap off the filter holder outlet and any open impinger inlets and outlets. The tester may use ground-glass stoppers, plastic caps, or serum caps to close these openings.

Transfer the probe and filter-impinger assembly to an area that is clean and protected from the wind so that the chances of contaminating or losing the sample is minimized.

Inspect the train before and during disassembly, and note any abnormal conditions. Treat the samples as follows:

7.2.1 *Container No. 1* (Probe, Filter, and Impinger Catches). Using a graduated cylinder, measure to the nearest ml, and record the volume of the water in the first three impingers; include any condensate in the probe in this determination. Transfer the impinger water from the graduated cylinder into this polyethylene container. Add the filter to this container. (The filter may be handled separately using procedures subject to the Administrator's approval.) Taking care that dust on the outside of the probe or other exterior surfaces does not get into the sample, clean all sample-exposed surfaces (including the probe nozzle, probe fitting, probe liner, first three impingers, impinger connectors, and filter holder) with deionized distilled water. Use less than 500 ml for the entire wash. Add the washings to the sampler container. Perform the deionized distilled water rinses as follows:

Carefully remove the probe nozzle and rinse the inside surface with deionized distilled water from a wash bottle. Brush with a Nylon bristle brush, and rinse until the rinse shows no visible particles, after which make a final rinse of the inside surface. Brush and rinse the inside parts of the Swagelok fitting with deionized distilled water in a similar way.

Rinse the probe liner with deionized distilled water. While squirting the water into the upper end of the probe, tilt and rotate the probe so that all inside surfaces will be wetted with water. Let the water drain from the lower end into the sample container. The tester may use a funnel (glass or polyethylene) to aid in transferring the liquid washes to the container. Follow the rinse with a probe brush. Hold the probe in an inclined position, and squirt deionized distilled water into the upper end as the probe brush is being pushed with a twisting action through the probe. Hold the sample container underneath the lower end of the probe, and catch any water and particulate matter that is brushed from the probe. Run the brush through the probe three times or more. With stainless steel or other metal probes, run the brush through in the above prescribed manner at least six times since metal probes have small crevices in which particulate matter can be entrapped. Rinse the brush with deionized distilled water, and quantitatively collect these washings in the sample container. After the brushing, make a final rinse of the probe as described above.

It is recommended that two people clean the probe to minimize sample losses. Between sampling runs, keep brushes clean and protected from contamination.

Rinse the inside surface of each of the first three impingers (and connecting glassware) three separate times. Use a small portion of deionized distilled water for each rinse, and brush each sample-exposed surface with a Nylon bristle brush, to ensure recovery of fine particulate matter. Make a final rinse of each surface and of the brush.

After ensuring that all joints have been wiped clean of the silicone grease, brush and rinse with deionized distilled water the inside of the filter holder (front-half only, if filter is positioned between the third and fourth impingers). Brush and rinse each surface three times or more if needed. Make a final rinse of the brush and filter holder.

After all water washings and particulate matter have been collected in the sample container, tighten the lid so that water will not leak out when it is shipped to the laboratory. Mark the height of the fluid level to determine whether leakage occurs during transport. Label the container clearly to identify its contents.

7.2.2 *Container No. 2* (Sample Blank). Prepare a blank by placing an unused filter in a polyethylene container and adding a volume of water equal to the total volume in Container No. 1. Process the blank in the same manner as for Container No. 1.

7.2.3 *Container No. 3* (Silica Gel). Note the color of the indicating silica gel to determine whether it has been completely spent and make a notation of its condition. Transfer the silica gel from the fourth impinger to its original container and seal. The tester may use a funnel to pour the silica gel and a rubber policeman to remove the silica gel from the impinger. It is not necessary to remove the small amount of dust particles that may adhere to the impinger wall and are difficult to remove. Since the gain in weight is to be used for moisture calculations, do not use any water or other liquids to transfer the silica gel. If a balance is available in the field, the tester may follow the analytical procedure for Container No. 3 in Section 7.4.2.

7.3 Sample Preparation and Distillation. (Note the liquid levels in Containers No. 1 and No. 2 and confirm on the analysis sheet whether or not leakage occurred during transport. If noticeable leakage had occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results.) Treat the contents of each sample container as described below:

7.3.1 *Container No. 1* (Probe, Filter, and Impinger Catches). Filter this container's contents, including the sampling filter, through Whatman No. 541 filter paper, or equivalent, into a 1500-ml beaker.

7.3.1.1 If the filtrate volume exceeds 900 ml, make the filtrate basic (red to phenolphthalein) with NaOH, and evaporate to less than 900 ml.

7.3.1.2 Place the filtered material (including sampling filter) in a nickel crucible, add a few ml of deionized distilled water, and macerate the filters with a glass rod.

Add 100 mg CaO to the crucible, and mix the contents thoroughly to form a slurry. Add two drops of phenolphthalein indicator. Place the crucible in a hood under infrared lamps or on a hot plate at low heat. Evaporate the water completely. During the evaporation of the water, keep the slurry basic (red to phenolphthalein) to avoid loss of F. If the indicator turns colorless (acidic) during the evaporation, add CaO until the color turns red again.

After evaporation of the water, place the crucible on a hot plate under a hood and slowly increase the temperature until the Whatman No. 541 and sampling filters char. It may take several hours to completely char the filters.

Place the crucible in a cold muffle furnace. Gradually (to prevent smoking) increase the temperature to 600°C, and maintain until the contents are reduced to an ash. Remove the crucible from the furnace and allow to cool.

Add approximately 4 g of crushed NaOH to the crucible and mix. Return the crucible to the muffle furnace, and fuse the sample for 10 minutes at 600°C.

Remove the sample from the furnace, and cool to ambient temperature. Using several rinsings of warm deionized distilled water, transfer the contents of the crucible to the beaker containing the filtrate. To assure complete sample removal, rinse finally with two 20-ml portions of 25 percent H_2SO_4, and carefully add to the beaker. Mix well, and transfer to a 1-liter volumetric flask. Dilute to volume with deionized distilled water, and mix thoroughly. Allow any undissolved solids to settle.

7.3.2 *Container No. 2* (Sample Blank). Treat in the same manner as described in Section 7.3.1 above.

7.3.3 Adjustment of Acid/Water Ratio in Distillation Flask. (Use a protective shield when carrying out this procedure.) Place 400 ml of deionized distilled water in the distillation flask, and add 200 ml of concentrated H_2SO_4. (Caution: Observe standard precautions when mixing H_2SO_4 with water. Slowly add the acid to the flask with constant swirling.) Add some soft glass beads and several small pieces of broken glass tubing, and assemble the apparatus as shown in Figure 13A-2. Heat the flask until it reaches a temperature of 175°C to adjust the acid/water ratio for subsequent distillations. Discard the distillate.

7.3.4 Distillation. Cool the contents of the distillation flask to below 80°C. Pipet an aliquot of sample containing less than 10.0 mg F directly into the distillation flask, and add deionized distilled water to make a total volume of 220 ml added to the distillation flask. (To estimate the appropriate aliquot size, select an aliquot of the solution and treat as described in Section 7.4.1. This will be an approximation of the F content because of possible interfering ions.) Note: If the sample contains chloride, add 5 mg of Ag_2SO_4 to the flask for every mg of chloride.

Place a 250-ml volumetric flask at the condenser exit. Heat the flask as rapidly as possible with a Bunsen burner, and collect all the distillate up to 175°C. During heatup, play the burner flame up and down the side of the flask to prevent bumping. Conduct the distillation as rapidly as possible (15 minutes or less). Slow distillations have been found to produce low F recoveries. Caution: Be careful not to exceed 175°C to avoid causing H_2SO_4 to distill over.

If F distillation in the mg range is to be followed by a distillation in the fractional mg range, add 220 ml of deionized distilled water and distill it over as in the acid adjustment step to remove residual F from the distillation system.

The tester may use the acid in the distillation flask until there is carry-over of interferences or poor F recovery. Check for these every tenth distillation using a deionized distilled water blank and a standard solution. Change the acid whenever the F recovery is less than 90 percent or the blank value exceeds 0.1 μg/ml.

7.4 Analysis.

7.4.1 Containers No. 1 and No. 2. After distilling suitable aliquots from Containers No. 1 and No. 2 according to Section 7.3.4, dilute the distillate in the volumetric flasks to exactly 250 ml with deionized distilled water, and mix thoroughly. Pipet a suitable aliquot of each sample distillate (containing 10 to 40 μg F/ml) into a beaker, and dilute to 50 ml with deionized distilled water. Use the same aliquot size for the blank. Add 10 ml of SPADNS mixed reagent (6.3.13), and mix thoroughly.

After mixing, place the sample in a constant-temperature bath containing the standard solutions (see Section 8.2) for 30 minutes before reading the absorbance on the spectrophotometer.

Set the spectrophotometer to zero absorbance at 570 nm with the reference solution (6.3.12), and check the spectrophotometer calibration with the standard solution. Determine the absorbance of the samples, and determine the concentration from the calibration curve. If the concentration does not fall within the range of the calibration curve, repeat the procedure using a different size aliquot.

7.4.2 *Container No. 3* (Silica Gel). Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g using a balance. The tester may conduct this step in the field.

8. Calibration

Maintain a laboratory log of all calibrations.

8.1 Sampling Train. Calibrate the sampling train components according to the indicated sections in Method 5: Probe Nozzle (Section 5.1); Pitot Tube (Section 5.2); Metering System (Section 5.3); Probe heater (Section 5.4); Temperature Gauges (Section 5.5); Leak Check of Metering System (Section 5.6); and Barometer (Section 5.7).

8.2 Spectrophotometer. Prepare the blank standard by adding 10 ml of SPADNS mixed reagent to 50 ml of deionized distilled water. Accurately prepare a series of standards from the 0.01 mg F/ml standard fluoride solution (6.3.10) by diluting 0, 2, 4, 6, 8, 10, 12, and 14 ml to 100 ml with deionized distilled water. Pipet 50 ml from each solution and transfer each to a separate 100-ml beaker. Then add 10 ml of SPADNS mixed reagent to each. These standards will contain 0, 10, 20, 30, 40 50, 60, and 70 μg F (0 to 1.4 μg/ml), respectively.

After mixing, place the reference standards and reference solution in a constant temperature bath for 30 minutes before reading the absorbance with the spectrophotometer. Adjust all samples to this same temperature before analyzing.

With the spectrophotometer at 570 nm, use the reference solution (6.3.12) to set the absorbance to zero.

Determine the absorbance of the standards. Prepare a calibration curve by plotting μg F/50 ml versus absorbance on linear graph paper. Prepare the standard curve initially and thereafter whenever the SPADNS mixed reagent is newly made. Also, run a calibration standard with each set of samples and if it differs from the calibration curve by ±2 percent, prepare a new standard curve.

9. Calculations

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation. Other forms of the equations may be used, provided that they yield equivalent results.

9.1 Nomenclature.

A_d = Aliquot of distillate taken for color development, ml.

A_t = Aliquot of total sample added to still, ml.

B_{ws} = Water vapor in the gas stream, proportion by volume.

C_s = Concentration of F in stack gas, mg/m³, dry basis, corrected to standard conditions of 760 mm Hg (29.92 in. Hg) and 293°K (528°R).

F_t = Total F in sample, mg.

μg F = Concentration from the calibration curve, μg.

T_m = Absolute average dry gas meter temperature (see Figure 5-2 of Method 5), °K (°R).

T_s = Absolute average stack gas temperature (see Figure 5-2 of Method 5), °K (°R).

V_d = Volume of distillate collected, ml.

$V_{m(std)}$ = Volume of gas sample as measured by dry gas meter, corrected to standard conditions, dscm (dscf).

V_t = Total volume of F sample, after final dilution, ml.

$V_{w(std)}$ = Volume of water vapor in the gas sample, corrected to standard conditions, scm (scf).

9.2 Average Dry Gas Meter Temperature and Average Orifice Pressure Drop. See data sheet (Figure 5-2 of Method 5).

9.3 Dry Gas Volume. Calculate $V_{m(std)}$ and adjust for leakage, if necessary, using the equation in section 6.3 of Method 5.

9.4 Volume of Water Vapor and Moisture Content. Calculate the volume of water vapor $V_{w(std)}$ and moisture content B_{ws} from the data obtained in this method (Figure 13A-1); use Equations 5-2 and 5-3 of Method 5.

9.5 Concentration.

9.5.1 Total Fluoride in Sample. Calculate the amount of F in the sample using the following equation:

$$F_t = 10^{-3} \frac{V_t}{A_t} \frac{V_d}{A_d} (\mu g\ F) \qquad \text{Eq. 13A-1}$$

9.5.2 Fluoride Concentration in Stack Gas. Determine the F concentration in the stack gas using the following equation:

$$C_s = K \frac{F_t}{V_{m(std)}} \qquad \text{Eq. 13A-2}$$

Where:

K = 35.31 ft³/m³ if $V_{m(std)}$ is expressed in English units.

= 1.00 m³/m³ if $V_{m(std)}$ is expressed in metric units.

9.6 Isokinetic Variation and Acceptable Results. Use Method 5, Sections 6.11 and 6.12.

10. Bibliography

1. Bellack, Ervin. Simplified Fluoride Distillation Method. Journal of the American Water Works Association. *50*:5306. 1958.

2 Mitchell, W. J., J. C. Suggs, and F. J. Bergman. Collaborative Study of EPA method 13A and Method 13B. Publication No. EPA-600/4-77-050. Environmental Protection Agency. Research Triangle Park, North Carolina. December 1977.

3. Mitchell, W. J. and M. R. Midgett. Adequacy of Sampling Trains and Analytical Procedures Used for Fluoride. Atm. Environ. *10*:865-872. 1976.

Method 13B. Determination of Total Fluoride Emissions From Stationary Sources; Specific Ion Electrode Method

1. Applicability and Principle

1.1 Applicability. This method applies to the determination of fluoride (F) emissions from stationary sources as specified in the regulations. It does not measure fluorocarbons, such as freons.

1.2 Principle. Gaseous and particulate F are withdrawn isokinetically from the source and collected in water and on a filter. The total F is then determined by the specific ion electrode method.

2. Range and Sensitivity

The range of this method is 0.02 to 2.000 μg F/ml, however, measurements of less than 0.1 μg F/ml require extra care. Sensitivity has not been determined.

3. Interferences

Grease on sample-exposed surfaces may cause low F results because of adsorption.

4. Precision and Accuracy

4.1 Precision. The following estimates are based on a collaborative test done at a primary aluminum smelter. In the test, six laboratories each sampled the stack simultaneously using two sampling trains for a total of 12 samples per sampling run. Fluoride concentrations encountered during the test ranged from 0.1 to 1.4 mg F/m³. The within-laboratory and between-laboratory standard deviations, which include sampling and analysis errors, are 0.037 mg F/m³ with 60 degrees of freedom and 0.056 mg F/m³ with five degrees of freedom, respectively.

4.2 Accuracy. The collaborative test did not find any bias in the analytical method.

5. Apparatus

5.1 Sampling Train and Sample Recovery. Same as Method 13A, Sections 5.1 and 5.2, respectively.

5.2 Analysis. The following items are needed:

5.2.1 Distillation Apparatus, Bunsen Burner, Electric Muffle Furnace, Crucibles, Beakers, Volumetric Flasks, Erlenmeyer Flasks or Plastic Bottles, Constant Temperature Bath, and Balance. Same as Method 13A, Sections 5.3.1 to 5.3.9, respectively, except include also 100-ml polyethylene beakers.

5.2.2 Fluoride Ion Activity Sensing Electrode.

5.2.3 Reference Electrode. Single junction, sleeve type.

5.2.4 Electrometer. A pH meter with millivolt-scale capable of ±0.1-mv resolution, or a specific ion meter made specifically for specific ion use.

5.2.5 Magnetic Stirrer and TFE [2] Fluorocarbon-Coated Stirring Bars.

6. Reagents

6.1 Sampling and Sample Recovery. Same as Method 13A, Sections 6.1 and 6.2, respectively.

6.2 Analysis. Use ACS reagent grade chemicals (or equivalent), unless otherwise specified. The reagents needed for analysis are as follows:

6.2.1 Calcium Oxide (CaO). Certified grade containing 0.005 percent F or less.

6.2.2 Phenolphthalein Indicator. Dissolve 0.1 g of phenolphthalein in a mixture of 50 ml of 90 percent ethanol and 50 ml deionized distilled water.

6.2.3 Sodium Hydroxide (NaOH). Pellets.

6.2.4 Sulfuric Acid (H_2SO_4), Concentrated.

6.2.5 Filters. Whatman No. 541, or equivalent.

6.2.6 Water. From same container as 6.1.2 of Method 13A.

6.2.7 Sodium Hydroxide, 5 M. Dissolve 20 g of NaOH in 100 ml of deionized distilled water.

6.2.8 Sulfuric Acid, 25 percent (V/V). Mix 1 part of concentrated H_2SO_4 with 3 parts of deionized distilled water.

[2] Mention of any trade name or specific product does not constitute endorsement by the Environmental Protection Agency.

6.2.9 *Total Ionic Strength Adjustment Buffer (TISAB).* Place approximately 500 ml of deionized distilled water in a 1-liter beaker. Add 57 ml of glacial acetic acid, 58 g of sodium chloride, and 4 g of cyclohexylene dinitrilo tetraacetic acid. Stir to dissolve. Place the beaker in a water bath to cool it. Slowly add 5 M NaOH to the solution, measuring the pH continuously with a calibrated pH/reference electrode pair, until the pH is 5.3. Cool to room temperature. Pour into a 1-liter volumetric flask, and dilute to volume with deionized distilled water. Commercially prepared TISAB may be substituted for the above.

6.2.10 Fluoride Standard Solution, 0.1 M. Oven dry some sodium fluoride (NaF) for a minimum of 2 hours at 110°C, and store in a desiccator. Then add 4.2 g of NaF to a 1-liter volumetric flask, and add enough deionized distilled water to dissolve. Dilute to volume with deionized distilled water.

7. Procedure

7.1 Sampling, Sample Recovery, and Sample Preparation and Distillation. Same as Method 13A, Sections 7.1, 7.2, and 7.3, respectively, except the notes concerning chloride and sulfate interferences are not applicable.

7.2 Analysis.

7.2.1 Containers No. 1 and No. 2. Distill suitable aliquots from Containers No. 1 and No. 2. Dilute the distillate in the volumetric flasks to exactly 250 ml with deionized distilled water and mix thoroughly. Pipet a 25-ml aliquot from each of the distillate and separate beakers. Add an equal volume of TISAB, and mix. The sample should be at the same temperature as the calibration standards when measurements are made. If ambient laboratory temperature fluctuates more than ±2°C from the temperature at which the calibration standards were measured, condition samples and standards in a constant-temperature bath before measurement. Stir the sample with a magnetic stirrer during measurement to minimize electrode response time. If the stirrer generates enough heat to change solution termperature, place a piece of temperature insulating material such as cork, between the stirrer and the beaker. Hold dilute samples (below 10^{-4} M fluoride ion content) in polyethylene beakers during measurement.

Insert the fluoride and reference electrodes into the solution. When a steady millivolt reading is obtained, record it. This may take several minutes. Determine concentration from the calibration curve. Between electrode measurements, rinse the electrode with distilled water.

7.2.2 Container No. 3 (Silica Gel). Same as Method 13A, Section 7.4.2.

8. Calibration

Maintain a laboratory log of all calibrations.

8.1 Sampling Train. Same as Method 13A.

8.2 Fluoride Electrode. Prepare fluoride standardizing solutions by serial dilution of the 0.1 M fluoride standard solution. Pipet 10 ml of 0.1 M fluoride standard solution into a 100-ml volumetric flask, and make up to the mark with deionized distilled water for a 10^{-2} M standard solution. Use 10 ml of 10^{-2} M solution to make a 10^{-3} M solution in the same manner. Repeat the dilution procedure and make 10^{-4} and 10^{-5} solutions.

Pipet 50 ml of each standard into a separate beaker. Add 50 ml of TISAB to each beaker. Place the electrode in the most dilute standard solution. When a steady millivolt reading is obtained, plot the value on the linear axis of semilog graph paper versus concentration on the log axis. Plot the nominal value for concentration of the standard on the log axis, e.g., when 50 ml of 10^{-2} M standard is diluted with 50 ml of TISAB, the concentration is still designated "10^{-2} M."

Between measurements soak the fluoride sensing electrode in deionized distilled water for 30 seconds, and then remove and blot dry. Analyze the standards going from dilute to concentrated standards. A straight-line calibration curve will be obtained, with nominal concentrations of 10^{-4}, 10^{-3}, 10^{-2}, and 10^{-1} fluoride molarity on the log axis plotted versus electrode potential (in mv) on the linear scale. Some electrodes may be slightly nonlinear between 10^{-5} and 10^{-4} M. If this occurs, use additional standards between these two concentrations.

Calibrate the fluoride electrode daily, and check it hourly. Prepare fresh fluoride standardizing solutions daily (10^{-2} M or less). Store fluoride standardizing solutions in polyethylene or polypropylene containers. (*Note:* Certain specific ion meters have been designed specifically for fluoride electrode use and give a direct readout of fluoride ion concentration. These meters may be used in lieu of calibration curves for fluoride measurements over narrow concentration ranges. Calibrate the meter according to the manufacturer's instructions.)

9. Calculations

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

9.1 Nomenclature. Same as Method 13A, Section 9.1. In addition:

M = F concentration from calibration curve, molarity.

9.2 Average Dry Gas Meter Temperature and Average Orifice Pressure Drop, Dry Gas Volume, Volume of Water Vapor and Moisture Content, Fluroide Concentration in Stack Gas, and Isokinetic Variation and Acceptable Results. Same as Method 13A, Section 9.2 to 9.4, 9.5.2, and 9.6, respectively.

9.3 Fluoride in Sample. Calculate the amount of F in the sample using the following:

$$F_t = K \frac{T_t}{A_t} (V_d) (M) \qquad \text{Equation 13B-1}$$

Where:

K = 19 mg/ml.

10. References

1. Same as Method 13A, Citations 1 and 2 of Section 10.

2. MacLeod, Kathryn E. and Howard L. Crist. Comparison of the SPADNS—Zirconium Lake and Specific Ion Electrode Methods of Fluoride Determination in Stack Emission Samples. Analytical Chemistry. *45*:1272–1273. 1973.

[FR Doc 80-18658 Filed 6-19-80; 8:45 am]

BILLING CODE 6560-01-M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1442-1]

Standards of Performance for New Stationary Sources Primary Aluminum Industry; Amendments

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The amendments permit fluoride emissions to exceed, under certain circumstances, emission limits contained in the previously promulgated standards of performance for new primary aluminum plants. Such excursions cannot be more than 0.3 kg/Mg of aluminum produced (0.6 lb/ton) above the promulgated standards of 0.95 kg/Mg (1.9 lb/ton) and 1.0 kg/Mg (2.0 lb/ton) for prebake and Soderberg plants, respectively. For an excursion to be allowed, a proper emission control system must have been installed and properly operated and maintained at the time of the excursion. The intended effect of these amendments is to take into account an inherent variability of fluoride emissions from the aluminum reduction process.

The amendments require monthly testing of emissions and revise Reference Method 14 for measuring fluoride emission rates. The amendments also respond to arguments raised during litigation of the standards of performance.

DATES: The effective date of the amendments is June 30, 1980. The applicability date of the amendments is October 23, 1974. All primary aluminum plants which commence construction on and after the applicability date are subject to the standards of performance, as amended here.

ADDRESSES: *Background Information Document.* The background information documents for the proposed and final amendments may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone (919) 541-2777. Please refer to *Primary Aluminum Background Information: Proposed Amendments* (EPA 450/2-76-025a) and *Promulgated Amendments* (EPA 450/3-79-026).

Docket: Docket No. OAQPS-78-10, containing supporting information used to develop the amendments, is available for public inspection and copying between 8:00 a.m. and 4.00 p.m., Monday through Friday, at EPA's Central Docket Section, Room 2902, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: John Crenshaw, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5477.

SUPPLEMENTARY INFORMATION:

Final Amendments

The amendments allow fluoride emissions from aluminum plant potrooms to exceed the original limits of 0.95 kg/Mg (1.9 lb/ton) for prebake plants and 1.0 kg/Mg (2.0 lb/ton) for Soderberg plants if the owner or operator of the plant can establish that a proper emission control system was installed and properly operated and maintained at the time the excursion above the original limits occurred. Emissions may not, however, exceed 1.25 kg/Mg (2.5 lb/ton) for prebake plants and 1.3 kg/Mg (2.6 lb/ton) for Soderberg plants at any time.

The amendments also require performance testing to be conducted at least once each month throughout the life of the plant. The owner or operator of a new plant may apply to the Administrator for an exemption from the monthly testing requirement for the primary control system and the anode bake plant. An exemption from the testing of secondary emissions from roof monitors, however, is not permitted.

Finally, the amendments: (1) require the potroom anemometers and associated equipment used in conjunction with Reference Method 14 to be checked for calibration once each year, unless the anemometers are found to be out of calibration, in which case an alternative schedule would be implemented; (2) clarify other Reference Method 14 procedures; (3) clarify the definition of *potroom group;* (4) replace English and metric units of measure with the International System of Units (SI); and (5) clarify the procedure for determining the rate of aluminum production for fluoride emission calculations. The amendments do not change the fluoride emission limit of 0.05 kg/Mg (0.1 lb/ton) of aluminum equivalent for anode baking facilities at prebake plants.

Summary of Environmental, Economic, and Energy Impacts

The amendments allow excursions above the original standard, but only under certain conditions. Each excursion must be reported to the Administrator and the adequacy of control equipment and operating and maintenance procedures must be established by the plant owner or operator. Based on emission test results at the Anaconda Aluminum Company's Sebree, Kentucky plant, such excursions may be expected approximately eight percent of the time. Assuming that each of these excursions is at the upper limit allowed (1.25 kg/Mg for a prebake plant), fluoride emissions from a typical new primary aluminum plant could be around three to four percent higher (3.8 Mg/yr, or 4.2 tons/yr, more) than had been originally calculated. It is important to stress that excursions are expected to occur at any new plant trying to meet the original standards; the amendments simply acknowledge that some excursions are unavoidable.

Although the emission control efficiency required by the original standards is still required, it would be theoretically possible to operate a new plant so that emissions were always at the upper limit permitted by these amendments. Using this "worst case" assumption, fluoride emissions from a typical new primary aluminum plant could increase above levels associated with the original emission limits by about 30 percent, or 33 Mg/yr (36 tons/yr). Assuming that two new plants become subject to the amended standards during the next five years, nationwide emissions of fluorides during that period could increase by 66 Mg/yr (72 tons/yr) above the levels which would result if the original limits were in effect. No other environmental impacts are associated with the amendments.

The amendments will result in performance test costs of about $415,000/yr during the first year and $330,000/yr during succeeding years of operation of a new plant. The increase in annualized costs, however, would be less than 0.5 percent for the first and succeeding years. There are no other significant costs associated with the amendments.

No increase in energy consumption will result from the amendments. The environmental, economic, and energy impacts are discussed in greater detail in *Primary Aluminum Background Information: Promulgated Amendments* (EPA 450/3-79-026).

Background

Standards of performance for new primary aluminum plants were proposed on October 23, 1974 (39 FR 37730), and promulgated on January 26, 1976 (41 FR 3826). These standards limited fluoride emissions to 1.0 kg/Mg (2 lb/ton) for Soderberg plants, 0.95 kg/Mg (1.9 lb/ton) for prebake plants, and 0.05 kg/Mg (0.1 lb/ton) for anode bake plants. There are two emission sources from Soderberg and prebake plants. The first source is the primary control system, which includes hoods to capture emissions from the pots and the control device

used to treat these emissions; the exhaust from this system still contains some fluorides. The second source is the roof monitor, through which flow the emissions (called secondary, or roof monitor, emissions) not captured by the primary control system. A few plants use secondary control systems to capture and collect roof monitor emissions.

Shortly after promulgation, petitions for review of the standards were filed by four aluminum companies. The principal argument raised by the petitioners was that the emission limits contained in the standards were too stringent and could not be achieved consistently by new, well-controlled facilities. Facilities which commenced construction prior to October 23, 1974, are not affected by the standard. Following discussions with the petitioning aluminum companies, EPA conducted an emission test program at the Anaconda Aluminum Company' plant in Sebree, Kentucky. At the time of testing, the Sebree plant was the newest primary aluminum plant in the United States, and its emission control system was considered by the Administrator representative of the best technological system of continuous emission reduction. The purpose of the test program was to gather additional data for reevaluating the standards. The test results were available in August of 1977 and indicated that emissions for a new, well-controlled plant could exceed the original emission limits approximately eight percent of the time. The amendments proposed on September 19, 1978 (43 FR 42186) and promulgated here address this potential problem by amending the standards to permit excursions of fluoride emissions up to 0.3 kg/Mg (0.6 lb/ton) above the emission limits contained in the original standards provided that proper control equipment was installed and properly operated and maintained during the time the excursion occurred.

In addition to amending the original standards, EPA has revised Reference Method 14 to reflect knowledge gained during the Sebree test program. The revisions clarify and improve the reliability of the testing procedures, but do not change the basic test method and, therefore, do not invalidate earlier Method 14 test results.

Rationale

The Administrator's decision to amend the existing standard is based primarily on the results of the Sebree test program. The test results may be summarized as follows: (1) the measured emissions were variable, ranging from 0.43 to 1.37 kg/Mg (0.85 to 2.74 lb/ton) for single test runs; and (2) emission variability appeared to be inherent in the production process and beyond the control of plant personnel. Since the Sebree plant represents a best technological system of continuous emission reduction for new aluminum plants, the Administrator expects that the other new plants covered by the standard will also exhibit emission variability.

An EPA analysis of the nine Sebree test runs indicates that there is about eight percent probability that a performance test would violate the current standard. [A performance test is defined in 40 CFR 60.8(f) as the arithmetic mean of three separate test runs, except in situations where a run must be discounted or canceled and the Administrator approves using the arithmetic mean of two runs.] The petitioners have estimated chances of a violation ranging from about 2.5 to 10 percent. Although the Sebree data base is not large enough to permit a thorough statistical analysis, the Administrator believes it is adequate to demonstrate a need for amending the current standard.

The approach selected is to amend Subpart S to allow a performance test result to be above the current standard provided the owner or operator submits to EPA a report clearly demonstrating that the emission control system was properly operated and maintained during the excursion above the standard. The report would be used as evidence that the high emission level resulted from random and uncontrollable emission variability, and that the emission variability was entirely beyond the control of the owner or operator of the affected facility. Under no circumstances, however, would performance test results be allowed above 1.25 kg/Mg (2.5 lb/ton) for prebake plants or 1.3 kg/Mg (2.6 lb/ton) for Soderberg plants. The Administrator believes that emissions from a plant equipped with the proper control system which is properly operated and maintained would be below these limits at all times.

For performance test results which fall between the original standard and the 1.25 or 1.3 kg/Mg upper limit to be considered excursions rather than violations, the owner or operator of the affected facility must, within 15 days of receipt of such performance test results, submit a report to the Enforcement Division of the appropriate EPA Regional Office. As a minimum, the report should establish that all necessary control devices were on-line and operating properly during the performance test, describe the operation and maintenance procedures followed, and set forth any explanation for the excursion.

The amendments also require, following the initial performance test required under 40 CFR 60.8(a), additional performance testing at least once each month during the life of the affected facility. During visits to existing plants, EPA personnel have observed that the emission control systems are not always operated and maintained as well as possible. The Administrator believes that good operation and maintenance of control systems are essential and expects the monthly testing requirement to help achieve this goal. The Administrator has the authority under section 114 of the Clean Air Act to require additional testing if necessary.

It is important to emphasize that the purpose of the amendments is to allow for inherent emission variability, not to permit substandard control equipment installation, operation or maintenance. Unfortunately, proper control equipment and proper operation and maintenance are difficult to describe and may vary considerably on a case-by-case basis. There are, however, a few guidelines that can be used as indicators.

The first guideline is that the control equipment should be designed to meet the original standard. This means a 95–97 percent overall control efficiency (capture efficiency times collection efficiency) for a potroom group. Equipment capable of this level of control is described in the background document (EPA 450/2–74–020a). Assuming proper control equipment is installed, the adequacy of operating and maintenance procedures can be evaluated on the basis of the frequency of excursions above the original standard. Based on the Sebree test results, more than one excursion per year (assuming performance tests are conducted monthly) may indicate a problem. Note, however, that legally every performance test result could be an excursion as long as proper equipment, operation and maintenance are shown.

As a guide to proper operation and maintenance, the following are considered basic to good control of emissions:

(1) Hood covers should fit properly and be in good repair;

(2) If the exhaust system is equipped with an adjustable air damper system, the hood exhaust rate for individual pots should be increased whenever hood covers are removed from a pot (the exhaust system should not, however, be overloaded by placing too many pots on high exhaust);

(3) Hood covers should be replaced as soon as possible after each potroom operation;

(4) Dust entrainment should be minimized during materials handling operations and sweeping of the working aisles;

(5) Only tapping crucibles with functional aspirator air return systems (for returning gases under the collection hooding) should be used; and

(6) The primary control system should be regularly inspected and properly maintained.

The amendments affect not only prebake designs such as the Sebree plant, but also Soderberg plants. Available data for existing plants indicate that Soderberg and prebake plants have similar emission variability. Thus, the Administrator feels justified in extrapolating the conclusions about the Sebree prebake plant to cover Soderberg designs. It is unlikely that any new Soderberg plant will be built due to the high cost of emission control for these designs. However, existing Soderberg plants may be modified to such an extent that they would be subject to these regulations.

Under the amendments, anode bake plants would be subject to the monthly testing requirement, but emissions would not be allowed under any circumstances to be above the level of the current bake plant standard. Since there is no evidence that bake plant emissions are as variable as potroom emissions, there is no need to allow for excursions above the bake plant standard.

The amendments allow the owner or operator of a new plant to apply to the Administrator for an exemption from the monthly testing requirement for the primary control system and the anode bake plant. The Administrator believes that the testing of these systems as often as once each month may be unreasonable given that (1) the contribution of primary and bake plant emissions (after exhausting from the primary control system) to the total emission rate is minor, averaging about 2.5 and 5 percent, respectively; (2) primary and bake plant emissions are much less variable than secondary emissions; and (3) the cost of primary and bake plant emissions sampling is high. An application to the Administrator for an exemption from monthly testing would be required to include (1) evidence that the primary and bake plant emissions have low variability; (2) an alternative testing schedule; and (3) the method to be used to determine primary control system emissions for the purpose of calculating total fluoride emissions from the potroom group.

The Administrator estimates the costs associated with monthly performance testing to average about $4,200 for primary tests, $5,100 for secondary tests, and $4,200 for bake plant tests. These estimates assume that (1) testing would be performed by plant personnel; (2) each monthly performance test would consist of the average of three 24 hour runs; (3) sampling would be performed by two crews working 13-hour shifts; (4) primary control system sampling would be performed at a single point in the stack; and (5) Sebree in-house testing costs would be representative of average costs for other new plants. Although these assumptions may not hold for all situations, the Administrator believes they provide a representative estimate of what testing costs would be for new plants.

Also amended is the procedure for determining the rate of aluminum production. Previously, the rate was based on the weight of metal tapped during the test period. However, since the weight of metal tapped does not always equal the weight of metal produced, undertapping or overtapping during a test period would result in erroneous production rates. The Administrator believes it is more reasonable to judge the weight of metal produced according to the weight of metal tapped during a 30-day period (720 hours) prior to and including the test date. The 30-day period allows overtapping and undertapping to average out, and gives a more accurate estimate of the true production rate.

Public Comments

Upon proposal of the amendments, the public was invited to submit written comments on all aspects of the amendments and Reference Method 14 revisions. These comments were reviewed and considered in developing the final amendments. All of the comments received are summarized and discussed in *Primary Aluminum Background Information: Promulgated Amendments* (EPA 450/3-79-026).

The most significant change resulting from these comments concerns the requirement in Reference Method 14 to periodically check the calibration of the anemometers located in the roof monitors of aluminum plant potrooms. The use of anemometers is required by the test method to determine the velocity and flow rate of air exiting the potroom roofs. Commenters felt that the proposed requirement to check anemometer calibration every month was unnecessary and would lead to substantially increased costs.

Review of anemometer calibration data indicates that anemometer calibration checks as often as every month are unnecessary. Consequently, Reference Method 14 has been revised to require an anemometer calibration check 12 months after the initial anemometer installation. The results of this check will be used to determine the schedule of subsequent anemometer checks.

Several commenters noted that the proposed requirement to conduct performance testing at least once each month throughout the life of a new primary aluminum plant would impose a large economic burden on the plant. In general, the commenters believed that testing at less frequent intervals should be sufficient to determine compliance with the standard. Three alternatives to monthly performance testing were suggested:

(1) One commenter believed that an initial performance test would be sufficient to demonstrate compliance. Periodic visual inspections could then be used to determine whether the control systems were being properly maintained. If the visual inspections indicated that maintenance was poor, monthly testing could then be required. This procedure would not impose the burden of monthly testing on the entire industry.

(2) Another commenter, noting that the proposed monthly testing requirement was excessively stringent, recommended that criteria be established for determining when monthly testing is required. For example, testing could be performed on a semi-annual basis until a violation occurred, when testing would revert to a monthly schedule.

(3) A third commenter suggested that the provisions permitting the Administrator, upon application, to establish an alternative test schedule for primary and bake plant emissions be extended to include secondary emissions. For example, quarterly testing of secondary emissions could be required until a violation occurred. Monthly testing could then be invoked for some period of time, possibly six months, until emissions were once again consistently below the level of the standard. Quarterly testing would then resume.

During the development of the amendments, the administrator learned that the operation and maintenance of aluminum plant emission control systems had seriously deteriorated during the past several years. The Administrator believes that regular emission testing will help remedy this situation by providing an incentive for

good operation and maintenance throughout the life of the plant. Although no continuous monitoring method is available, the level of roof monitor emissions provides a good indication of the adequacy of operation and maintenance procedures for the most sensitive portion of the primary control system: capture of the pot emissions. The frequency of testing selected—once per month—is a judgmental compromise between high testing costs (as would occur with weekly tests) and the possibility of inadequate maintenance between tests (which seems more likely to occur as the time between tests increases).

In evaluating comments on the proposed monthly testing requirement, the administrator focused his attention on costs. Since the cost of the monthly testing requirement is less than 0.5 percent of the annualized costs of a typical primary aluminum plant, the Administrator considered the requirement reasonable.

The original standards required potroom emissions to be below 0.95 kg/Mg (1.9 lb/ton) for prebake plants and 1.0 kg/Mg (2.0 lb/ton) for Soderberg plants. One commenter, noting that the 0.05 kg/Mg (0.1 lb/ton) difference between the standards is reasonable in view of the differences between the two types of plants, felt this same reasoning should be followed in developing the proposed never-to-be-exceeded limit of 1.25 kg/Mg (2.5 lb/ton) which applied to both prebake and Soderberg plants. The commenter recommended that a never-to-be-exceeded limit of 1.3 kg/Mg (2.6 lb/ton) be established for Soderberg plants while retaining the proposed 1.25 kg/Mg (2.5 lb/ton) limit for prebake plants.

This comment is incorporated in the final amendments, which allow emissions from Soderberg plants where exemplary operation and maintenance of the emission control systems has been demonstrated to be as high as 1.3 kg/Mg (2.6 lb/ton).

One commenter expressed concern over the correct number or Reference Method 14 sampling manifolds to be located in potroom groups where two or more potroom segments are ducted to a common control system. The regulation defines *potroom group* as an uncontrolled potroom, a potroom which is controlled individually, or a group of potrooms or potroom segments ducted to a common control system. In situations where a potroom group consists of a group of potroom segments ducted to a common control system, the manifold would be installed in only one potroom segment. The manifold may not be divided among potroom segments however, additional sampling manifolds may be installed in the other segments, if desired.

When only one manifold is located in a potroom group, care must be taken to ensure that operations are normal in the potroom segments where manifolds are not located, but which are ducted to the same control system. During normal operation, most pots should be operating, no major upsets should occur, and the operating and maintenance procedures followed in each potroom segment, including the segment tested, should be the same. Otherwise, the emission levels measured in the tested potroom segment may not be representative of emission levels in the other potroom segments.

One commenter felt that the amendments would unjustly require the use of tapping crucibles with aspirator air return systems, since the preamble for the proposed amendment stated that certain operating and maintenance procedures, including the use of aspirator air return systems, represent good emission control and should be implemented. Although this statement reflects the Administrator's judgment about which procedures would enable the standards to be achieved, the regulation does not actually require that these procedures be implemented. Instead these procedures provide useful guidance for improving emission control when the standards are being exceeded

If emissions are below 0.95 kg/Mg (1.9 lb/ton) for prebake potrooms and 1.0 kg/Mg (2.0 lb/ton) for Soderberg potrooms, any combination of procedures may be used. If emission levels are between 0.95 and 1.25 kg/Mg (1.9 and 2.5 lb/ton) for prebake potrooms or 1.0 and 1.3 kg/Mg (2.0 and 2.6 lb/ton) for Soderberg potrooms, the regulation requires the owner or operator of a plant to demonstrate that exemplary operating and maintenance procedures were used. Otherwise the excursion is considered a violation of the standard. The Administrator has not defined exemplary operating and maintenance procedures in the regulation because different plants, depending on plant design, may incorporate different procedures, but the basic procedures listed in the preamble rationale provide guidance as to which operating and maintenance procedures should be effected to reduce or prevent excursions.

Several commenters expressed concern that the standards of performance and test methods would be applied to existing primary aluminum plants. It is emphasized, however, that the standards and test methods apply only to new, modified, or reconstructed plants. Existing plants often differ in design from new plants and cannot be controlled to the same level, except at much higher costs. As an aid to the States in controlling emissions from existing primary aluminum plants, the Administrator has recently published draft emission guidelines for existing plants (44 FR 21754). These draft guidelines may be obtained from the U.S. EPA Library. Request *Primary Aluminum Draft Guidelines for Control of Fluoride Emissions from Existing Primary Aluminum Plants* (EPA 450/2-78-049a).

Another commenter was concerned about the required length of each test run. Section 5.3.4 of Reference Method 14 states that each test run shall last at least eight hours, and if a question exists as to the representativeness of an eight-hour period, a longer period should be selected. It is essential that the sampling period be representative of all potroom operations and events, including tapping, carbon setting, and tracking. For most recently-constructed plants, 24 hours are required for all potroom operations and events to occur in the area beneath the sampling manifold. Thus, a 24-hour sampling period would be necessary for these plants.

Another commenter expressed concern about the procedure for conducting performance tests. The General Provisions for standards of performance for new stationary sources [40 CFR 60.8(f)] state that each performance test shall consist of the arithmetic mean of three separate test runs. Although the results of the three test runs are to be calculated separately, the runs may be conducted consecutively, as was done during the Sebree test program.

One commenter suggested that the rate of aluminum production, as used to calculate final emission rates, be based on the weight of metal tapped during the month in which testing was performed rather than on the test date. This, the commenter believed, would be a more convenient and practical method for calculating the aluminum production rate because production records are commonly kept on a monthly basis. The Administrator believes, however, that if the rate of aluminum production were determined on a calendar-month basis, as the commenter suggests, then in situations where testing is conducted at the beginning of a month, the final test results would not be known until the end of the month. This delay could allow emissions to be above the standard for nearly an entire month before a violation could be determined and corrective actions taken. It is

preferable that the test results be known as soon as possible after the testing is completed, as provided for in the proposed and final amendments.

As a result of comments, several other minor changes were made to the proposal. These include provisions allowing an owner or operator the option of: (1) installing anemometers halfway across the width of the potroom roof monitor; (2) balancing the sampling manifold for flow rate prior to its installation in the roof monitor; or (3) making anemometer installations non-permanent.

Docket

The docket is an organized and complete file of all the information submitted to or otherwise considered in the development of this rulemaking. The principal purposes of the docket are: (1) to allow interested parties to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process; and (2) to serve as the record in case of judicial review. The docket is available for public inspection and copying, as noted under ADDRESSES.

Miscellaneous

The proposed amendments contained a revision to Section 60.8(d) of the General Provisions which would have allowed the owner or operator to give less than 30 days prior notice of testing if required to do so in specific regulations. Since this revision has already been promulgated with another regulation (44 FR 33580), it is not contained in the final amendments promulgated here.

The final amendments do not alter the applicability date of the original standards. The standards continue to apply to all new primary aluminum plants for which construction or modification began on or after October 23, 1974, the original proposal date.

As prescribed by section 111 of the Clean Air Act, promulgation of the original standards of performance (41 FR 3826) was preceded by the Administrator's determination that primary aluminum plants contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare. In accordance with section 117 of the Act, publication of the originally proposed standards (39 FR 37730) was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect:

> ". . . application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [section 111(a)(1)].

Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act requires (or has the potential for requiring) the imposition of a more stringent emission standard in several situations.

For example, applicable costs do not necessarily play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources locating in nonattainment areas, i.e., those areas where statutorily-mandated health and welfare standards are being violated. In this respect, section 173 of the Act requires that new or modified sources constructed in an area which exceeds the National Ambient Air Quality Standard (NAAQS) must reduce emissions to the level which reflects the "lowest achievable emission rate" (LAER), as defined in section 171(3) for such category of source. The statute defines LAER as that rate of emissions based on the following, whichever is more stringent:

> (A) The most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or
>
> (B) The most stringent emission limitation which is achieved in practice by such class or category of source.

In no event can the emission rate exceed any applicable new source performance standard (section 171(3)).

A similar situation may arise under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require that certain sources (referred to in section 169(1)) employ "best available control technology" (BACT) as defined in section 169(3) for all pollutants regulated under the Act. Best available control technology must be determined on a case-by-case basis, taking energy, environmental and economic impacts and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the Act.

In all events, State Implementation Plans (SIP's) approved or promulgated under section 110 of the Act must provide for the attainment and maintenance of NAAQS designed to protect public health and welfare. For this purpose, SIP's must in some cases require greater emission reduction than those required by standards of performance for new sources.

Finally, States are free under section 116 of the Act to establish even more stringent limits than those established under section 111 and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment and environmental impact statement for substantial revisions to standards of performance. Although these amendments are not substantial revisions, certain economic information was developed and is presented in *Primary Aluminum Background Information: Promulgated Amendments* (EPA 450/3-79-026). The revisions to the standards of performance were not significant enough to warrant preparation of an environmental impact statement.

Dated: June 24, 1980.

Douglas M. Costle,

Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

40 CFR Part 60 is revised as follows:

1. Subpart S is revised to read as follows:

Subpart S—Standards of Performance for Primary Aluminum Reduction Plants

Authority: Sections 111 and 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

Section 60.190 paragraph (a) is revised as follows:

§ 60.190 Applicability and designation of affected facility.

(a) The affected facilities in primary aluminum reduction plants to which this subpart applies are potroom groups and anode bake plants.

* * * * *

Section 60.191 is revised to read as follows:

§ 60.191 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

"Aluminum equivalent" means an amount of aluminum which can be produced from a Mg of anodes produced by an anode bake plant as determined by § 60.195(g).

"Anode bake plant" means a facility which produces carbon anodes for use in a primary aluminum reduction plant.

"Potroom" means a building unit which houses a group of electrolytic cells in which aluminum is produced.

"Potroom group" means an uncontrolled potroom, a potroom which is controlled individually, or a group of potrooms or potroom segments ducted to a common control system.

"Primary aluminum reduction plant" means any facility manufacturing aluminum by electrolytic reduction.

"Primary control system" means an air pollution control system designed to remove gaseous and particulate flourides from exhaust gases which are captured at the cell.

"Roof monitor" means that portion of the roof of a potroom where gases not captured at the cell exit from the potroom.

"Total fluorides" means elemental fluorine and all fluoride compounds as measured by reference methods specified in § 60.195 or by equivalent or alternative methods (see § 60.8(b)).

Section 60.192 is revised to read as follows:

§ 60.192 Standards for fluorides.

(a) On and after the date on which the initial performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases containing total fluorides, as measured according to § 60.8 above, in excess of:

(1) 1.0 kg/Mg (2.0 lb/ton) of aluminum produced for potroom groups at Soderberg plants; except that emissions between 1.0 kg/Mg and 1.3 kg/Mg (2.6 lb/ton) will be considered in compliance if the owner or operator demonstrates that exemplary operation and maintenance procedures were used with respect to the emission control system and that proper control equipment was operating at the affected facility during the performance tests;

(2) 0.95 kg/Mg (1.9 lb/ton) of aluminum produced for potroom groups at prebake plants; except that emissions between 0.95 kg/Mg and 1.25 kg/Mg (2.5 lb/ton) will be considered in compliance if the owner or operator demonstrates that exemplary operation and maintenance procedures were used with respect to the emission control system and that proper control equipment was operating at the affected facility during the performance test; and

(3) 0.05 kg/Mg (0.1 lb/ton) of aluminum equivalent for anode bake plants.

(b) Within 30 days of any performance test which reveals emissions which fall between the 1.0 kg/Mg and 1.3 kg/Mg levels in paragraph (a)(1) of this section or between the 0.95 kg/Mg and 1.25 kg/Mg levels in paragraph (a)(2) of this section, the owner or operator shall submit a report indicating whether all necessary control devices were on-line and operating properly during the performance test, describing the operating and maintenance procedures followed, and setting forth any explanation for the excess emissions, to the Director of the Enforcement Division of the appropriate EPA Regional Office.

Section 60.193 is revised to read as follows:

§ 60.193 Standard for visible emissions.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any potroom group any gases which exhibit 10 percent opacity or greater, or

(2) From any anode bake plant any gases which exhibit 20 percent opacity or greater.

Section 60.194 paragraphs (a) and (b) are revised as follows:

§ 60.194 Monitoring of operations.

(a) The owner or operator of any affected facility subject to the provisions of this subpart shall install, calibrate, maintain, and operate monitoring devices which can be used to determine daily the weight of aluminum and anode produced. The weighing devices shall have an accuracy of ± 5 percent over their operating range.

(b) The owner or operator of any affected facility shall maintain a record of daily production rates of aluminum and anodes, raw material feed rates, and cell or potline voltages.

(Section 114 of the Clean Air Act as amended (42 U.S.C. 7414))

* * * * *

Section 60.195 is revised as follows:

§ 60.195 Test methods and procedures.

(a) Following the initial performance test as required under § 60.8(a), an owner or operator shall conduct a performance test at least once each month during the life of the affected facility except when malfunctions prevent representative sampling, as provided under § 60.8(c). The owner or operator shall give the Administrator at least 15 days advance notice of each test. The Administrator may require additional testing under section 114 of the Clean Air Act.

(b) An owner or operator may petition the Administrator to establish an alternative testing requirement that requires testing less frequently than once each month for a primary control system or an anode bake plant. If the owner or operator show that emissions from the primary control system or the anode bake plant have low variability during day-to-day operations, the Administrator may establish such an alternative testing requirement. The alternative testing requirement shall include a testing schedule and, in the case of a primary control system, the method to be used to determine primary control system emissions for the purpose of performance tests. The Administrator shall publish the alternative testing requirement in the **Federal Register**.

(c) Except as provided in § 60.8(b), reference methods specified in Appendix A of this part shall be used to determine compliance with the standards prescribed in § 60.192 as follows:

(1) For sampling emissions from stacks:

(i) Method 1 for sample and velocity traverses,

(ii) Method 2 for velocity and volumetric flow rate,

(iii) Method 3 for gas analysis, and

(iv) Method 13A or 13B for the concentration of total fluorides and the associated moisture content.

(2) For sampling emissions from roof monitors not employing stacks or pollutant collection systems:

(i) Method 1 for sample and velocity traverses,

(ii) Method 2 and Method 14 for velocity and volumetric flow rate,

(iii) Method 3 for gas analysis, and

(iv) Method 14 for the concentration of total fluorides and associated moisture content.

(3) For sampling emissions from roof monitors not employing stacks but equipped with pollutant collection systems, the procedures under § 60.8(b) shall be followed.

(d) For Method 13A or 13B, the sampling time for each run shall be at least 8 hours for any potroom sample

and at least 4 hours for any anode bake plant sample, and the minimum sample volume shall be 6.8 dscm (240 dscf) for any potroom sample and 3.4 dscm (120 dscf) for any anode bake plant sample except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(e) The air pollution control system for each affected facility shall be constructed so that volumetric flow rates and total fluoride emissions can be accurately determined using applicable methods specified under paragraph (c) of this section.

(f) The rate of aluminum production is determined by dividing 720 hours into the weight of aluminum tapped from the affected facility during a period of 30 days prior to and including the final run of a performance test.

(g) For anode bake plants, the aluminum equivalent for anodes produced shall be determined as follows:

(1) Determine the average weight (Mg) of anode produced in anode bake plant during a representative oven cycle using a monitoring device which meets the requirements of § 60.194(a).

(2) Determine the average rate of anode production by dividing the total weight of anodes produced during the representative oven cycle by the length of the cycle in hours.

(3) Calculate the aluminum equivalent for anodes produced by multiplying the average rate of anode production by two. (Note: An owner or operator may establish a different multiplication factor by submitting production records of the Mg of aluminum produced and the concurrent Mg of anode consumed by potrooms.)

(h) For each run, potroom group emissions expressed in kg/Mg of aluminum produced shall be determined using the following equation:

$$Epg = \frac{(CsQs)_1 10^{-6} + (CsQs)_2 10^{-6}}{M}$$

Where:

Epg = potroom group emissions of total fluorides in kg/Mg of aluminum produced.

Cs = concentration of total fluorides in mg/dscm as determined by Method 13A or 13B, or by Method 14, as applicable.

Qs = volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2 and/or Method 14, as applicable.

10^{-6} = conversion factor from mg to kg.

M = rate of aluminum production in Mg/hr as determined by § 60.195(f).

$(CsQs)_1$ = product of Cs and Qs for measurements of primary control system effluent gas streams.

$(CsQs)_2$ = product of Cs and Qs for measurements of secondary control system or roof monitor effluent gas streams.

Where an alternative testing requirement has been established for the primary control system, the calculated value $(CsQs)_1$ from the most recent performance test will be used.

(i) For each run, as applicable, anode bake plant emissions expressed in kg/Mg of aluminum equivalent shall be determined using the following equation:

$$Ebp = \frac{CsQs\ 10^{-6}}{Me}$$

Where:

Ebp = anode bake plant emissions of total fluorides in kg/Mg of aluminum equivalent.

Cs = concentration of total fluorides in mg/dscm as determined by Method 13A or 13B.

Qs = volumetric flow rate of the effluent gas stream in dscm/hr as determined by Method 2.

10^{-6} = conversion factor from mg to kg.

Me = aluminum equivalent for anodes produced by anode bake plants in Mg/hr as determined by § 60.195(g).

(Section 114 of the Clean Air Act as amended (42 U.S.C. 7414))

2. Method 14, under Appendix A—Reference Methods, is revised to read as follows:

Appendix A—Reference Methods

* * * * *

METHOD 14—DETERMINATION OF *FLUORIDE EMISSIONS FROM POTROOM* ROOF MONITORS FOR PRIMARY ALUMINUM PLANTS

1. *Applicability and Principle*

1.1 Applicability. This method is applicable for the determination of fluoride emissions from stationary sources only when specified by the test procedures for determining compliance with new source performance standards.

1.2 Principle. Gaseous and particulate fluoride roof monitor emissions are drawn into a permanent sampling manifold through several large nozzles. The sample is transported from the sampling manifold to ground level through a duct. The gas in the duct is sampled using Method 13A or 13B—Determination of Total Fluoride Emissions from Stationary Sources. Effluent velocity and volumetric flow rate are determined with anemometers located in the roof monitor.

2. *Apparatus.*

2.1 Velocity measurement apparatus.

2.1.1 Anemometers. Propeller anemometers, or equivalent. Each anemometer shall meet the following specifications: (1) Its propeller shall be made of polystyrene, or similar material of uniform density. To insure uniformity of performance among propellers, it is desirable that all propellers be made from the same mold. (2) The propeller shall be properly balanced, to optimize performance; (3) When the anemometer is mounted horizontally, its threshold velocity shall not exceed 15 m/min (50 fpm); (4) The measurement range of the anemometer shall extend to at least 600 m/min (2,000 fpm); (5) The anemometer shall be able to withstand prolonged exposure to dusty and corrosive environments; one way of achieving this is to continuously purge the bearings of the anemometer with filtered air during operation; (6) All anemometer components shall be properly shielded or encased, such that the performance of the anemometer is uninfluenced by potroom magnetic field effects; (7) A known relationship shall exist between the electrical output signal from the anemometer generator and the propeller shaft rpm, at a minimum of three evenly spaced rpm settings between 60 and 1800 rpm; for the 3 settings, use 60±15, 900±100, and 1800±100 rpm. Anemometers having other types of output signals (e.g., optical) may be used, subject to the approval of the Administrator. If other types of anemometers are used, there must be a known relationship (as described above) between output signal and shaft rpm; also, each anemometer must be equipped with a suitable readout system (See Section 2.1.3).

2.1.2 Installation of anemometers.

2.1.2.1 If the affected facility consists of a single, isolated potroom (or potroom segment), install at least one anemometer for every 85 m of roof monitor length. If the length of the roof monitor divided by 85 m is not a whole number, round the fraction to the nearest whole number to determine the number of anemometers needed. For monitors that are less than 130 m in length, use at least two anemometers. Divide the monitor cross-section into as many equal areas as anemometers and locate an anemometer at the centroid of each equal area. See exception in Section 2.1.2.3.

2.1.2.2 If the affected facility consists of two or more potrooms (or potroom segments) ducted to a common control device, install anemometers in each potroom (or segment) that contains a sampling manifold. Install at least one anemometer for every 85 m of roof monitor length of the potroom (or segment). If the potroom (or segment) length divided by 85 is not a whole number, round the fraction to the nearest whole number to determine the number of anemometers needed. If the potroom (or segment) length is less than 130 m, use at least two anemometers. Divide the potroom (or segment) monitor cross-section into as many equal areas as anemometers and locate an anemometer at the centroid of each equal area. See exception in Section 2.1.2.3.

2.1.2.3 At least one anemometer shall be installed in the immediate vicinity (i.e., within 10 m) of the center of the manifold (See Section 2.2.1) For its placement in relation to the width of the monitor, there are

two alternatives. The first is to make a velocity traverse of the width of the roof monitor where an anemometer is to be placed and install the anemometer at a point of average velocity along this traverse. The traverse may be made with any suitable low velocity measuring device, and shall be made during normal process operating conditions.

The second alternative, at the option of the tester, is to install the anemometer halfway across the width of the roof monitor. In this latter case, the velocity traverse need not be conducted.

2.1.3 Recorders. Recorders, equipped with suitable auxiliary equipment (e.g. transducers) for converting the output signal from each anemometer to a continuous recording of air flow velocity, or to an integrated measure of volumetric flowrate. A suitable recorder is one that allows the output signal from the propeller anemometer to be read to within 1 percent when the velocity is between 100 and 120 m/min (350 and 400 fpm). For the purpose of recording velocity, "continuous" shall mean one readout per 15-minute or shorter time interval. A constant amount of time shall elapse between readings. Volumetric flow rate may be determined by an electrical count of anemometer revolutions. The recorders or counters shall permit identification of the velocities or flowrate measured by each individual anemometer.

2.1.4 Pitot tube. Standard-type pitot tube, as described in Section 2.7 of Method 2, and having a coefficient of 0.99±0.01.

2.1.5 Pitot tube (optional). Isolated, Type S pitot, as described in Section 2.1 of Method 2. The pitot tube shall have a known coefficient, determined as outlined in Section 4.1 of Method 2.

2.1.6 Differential pressure gauge. Inclined manometer or equivalent, as described in Section 2.1.2 of Method 2.

2.2 Roof monitor air sampling system.

2.2.1 Sampling ductwork. A minimum of one manifold system shall be installed for each potroom group (as defined in Subpart S, Section 60.191). The manifold system and connecting duct shall be permanently installed to draw an air sample from the roof monitor to ground level. A typical installation of a duct for drawing a sample from a roof monitor to ground level is shown in Figure 14-1. A plan of a manifold system that is located in a roof monitor is shown in Figure 14.2. These drawings represent a typical installation for a generalized roof monitor The dimensions on these figures may be altered slightly to make the manifold system fit into a particular roof monitor, but the general configuration shall be followed. There shall be eight nozzles, each having a diameter of 0.40 to 0.50 m. Unless otherwise specified by the Administrator, the length of the manifold system from the first nozzle to the eighth shall be 35 m or eight percent of the length of the potroom (or potroom segment) roof monitor, whichever is greater. The duct leading from the roof monitor manifold shall be round with a diameter of 0.30 to 0.40 m. As shown in Figure 14-2, each of the sample legs of the manifold shall have a device, such as a blast gate or valve, to enable adjustment of the flow into each sample nozzle.

BILLING CODE 6560-01-M

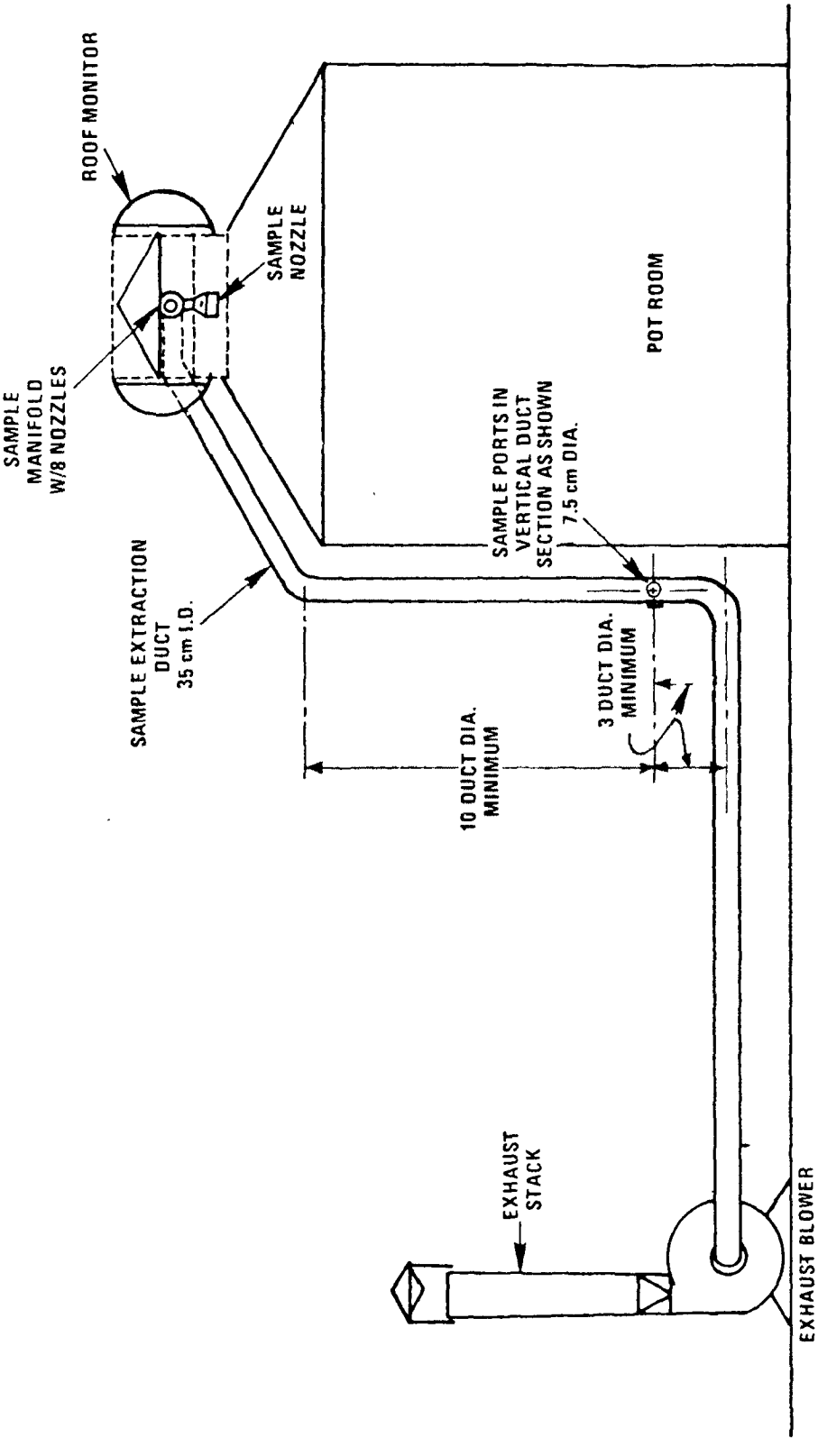


Figure 14-1. Roof monitor sampling system.

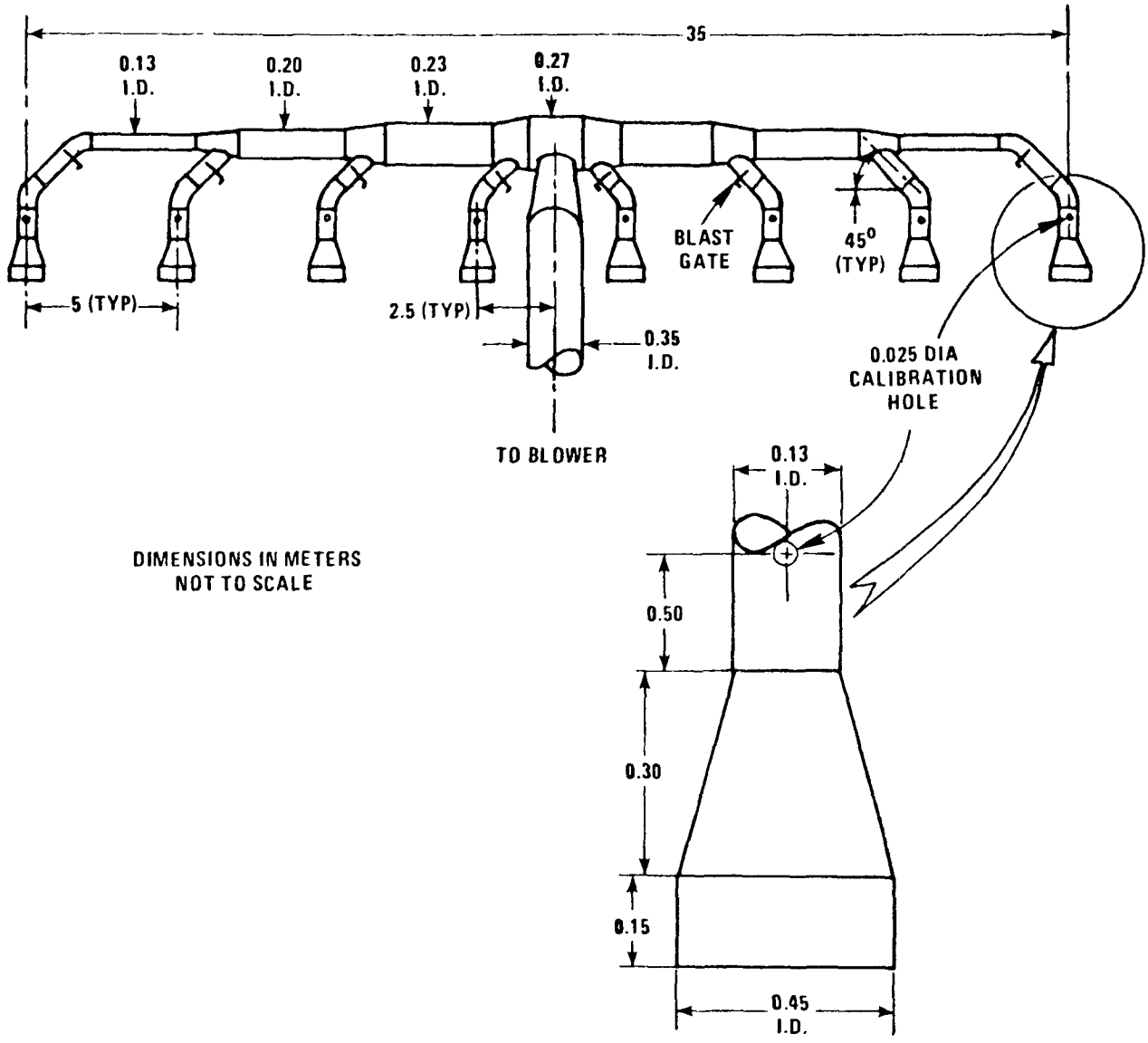


Figure 14 2 Sampling manifold and nozzles

BILLING CODE 6560-01-C

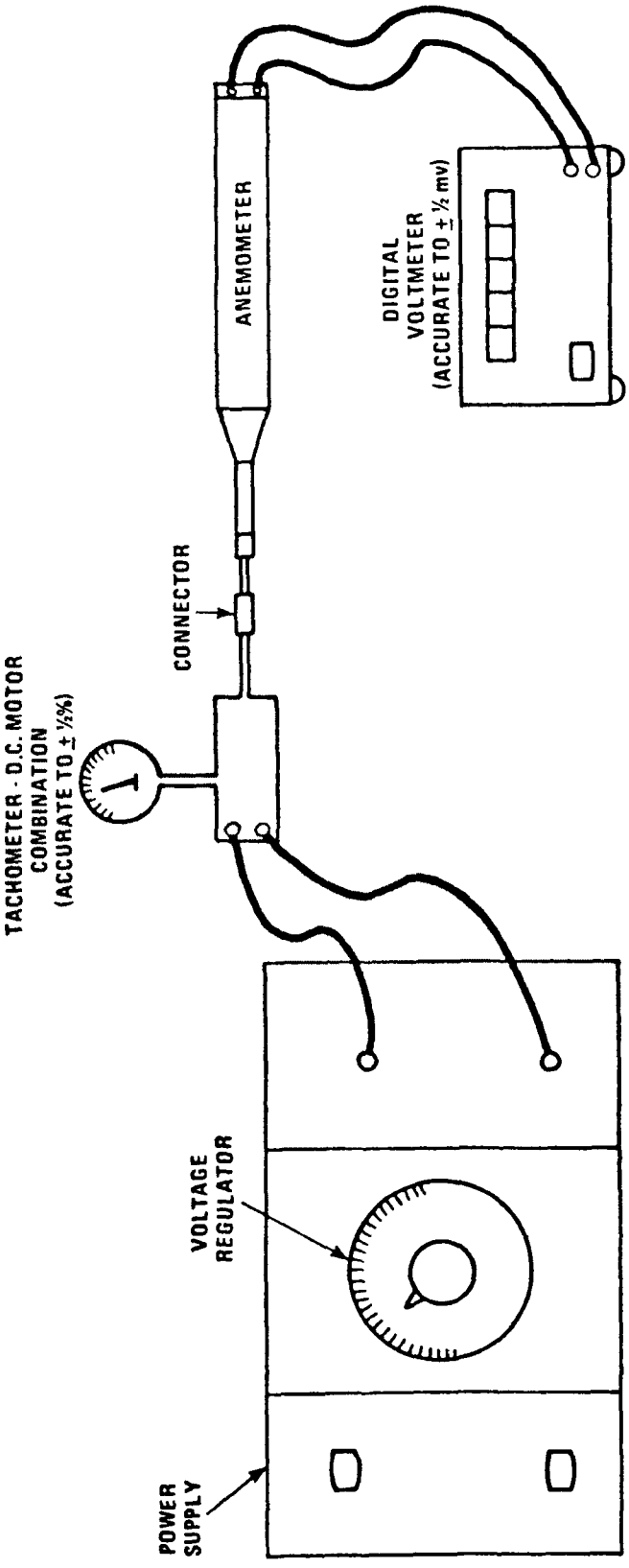


Figure 14-3. Typical RPM generator.

The manifold shall be located in the immediate vicinity of one of the propeller anemometers (see Section 2.1.2.3) and as close as possible to the midsection of the potroom (or potroom segment). Avoid locating the manifold near the end of a potroom or in a section where the aluminum reduction pot arrangement is not typical of the rest of the potroom (or potroom segment). Center the sample nozzles in the throat of the roof monitor (see Figure 14–1). Construct all sample-exposed surfaces within the nozzles, manifold and sample duct of 316 stainless steel. Aluminum may be used if a new ductwork system is conditioned with fluoride-laden roof monitor air for a period of six weeks prior to initial testing. Other materials of construction may be used if it is demonstrated through comparative testing that there is no loss of flourides in the system. All connections in the ductwork shall be leak free.

Locate two sample ports in a vertical section of the duct between the roof monitor and exhaust fan. The sample ports shall be at least 10 duct diameters downstream and three diameters upstream from any flow disturbance such as a bend or contraction. The two sample ports shall be situated 90° apart. One of the sample ports shall be situated so that the duct can be traversed in the plane of the nearest upstream duct bend.

2.2.2 Exhaust fan. An industrial fan or blower shall be attached to the sample duct at ground level (see Figure 14–1). This exhaust fan shall have a capacity such that a large enough volume of air can be pulled through the ductwork to maintain an isokinetic sampling rate in all the sample nozzles for all flow rates normally encountered in the roof monitor.

The exhaust fan volumetric flow rate shall be adjustable so that the roof monitor air can be drawn isokinetically into the sample nozzles. This control of flow may be achieved by a damper on the inlet to the exhauster or by any other workable method.

2.3 Temperature measurement apparatus.

2.3.1 Thermocouple. Install a thermocouple in the roof monitor near the sample duct. The thermocouple shall conform to the specifications outlined in Section 2.3 of Method 2.

2.3.2 Signal transducer. Transducer, to change the thermocouple voltage output to a temperature readout.

2.3.3 Thermocouple wire. To reach from roof monitor to signal transducer and recorder.

2.3.4 Recorder. Suitable recorder to monitor the output from the thermocouple signal transducer.

2.4 Fluoride sampling train. Use the train described in Method 13A or 13B.

3. *Reagents.*

3.1 Sampling and analysis. Use reagents described in Method 13A or 13B.

4. *Calibration.*

4.1 Initial performance checks. Conduct these checks within 60 days prior to the first performance test.

4.1.1 Propeller anemometers. Anemometers which meet the specifications outlined in Section 2.1.1 need not be calibrated, provided that a reference performance curve relating anemometer signal output to air velocity (covering the velocity range of interest) is available from the manufacturer. For the purpose of this method, a "reference" performance curve is defined as one that has been derived from primary standard calibration data, with the anemometer mounted vertically. "Primary standard" data are obtainable by: (1) Direct calibration of one or more of the anemometers by the National Bureau of Standards (NBS); (2) NBS-traceable calibration, or (3) Calibration by direct measurement of fundamental parameters such as length and time (e.g., by moving the anemometers through still air at measured rates of speed, and recording the output signals). If a reference performance curve is not available from the manufacturer, such a curve shall be generated, using one of the three methods described as above. Conduct a performance-check as outlined in Section 4.1.1.1 through 4.1.1.3, below. Alternatively, the tester may use any other suitable method, subject to the approval of the Administrator, that takes into account the signal output, propeller condition and threshold velocity of the anemometer.

4.1.1.1 Check the signal output of the anemometer by using an accurate rpm generator (see Figure 14–3) or synchronous motors to spin the propeller shaft at each of the three rpm settings described in Section 2.1.1 above (specification No. 7), and measuring the output signal at each setting. If, at each setting, the output signal is within ± 5 percent of the manufacturer's value, the anemometer can be used. If the anemometer performance is unsatisfactory, the anemometer shall either be replaced or repaired.

4.1.1.2 Check the propeller condition, by visually inspecting the propeller, making note of any significant damage or warpage; damaged or deformed propellers shall be replaced.

4.1.1.3 Check the anemometer threshold velocity as follows: With the anemometer mounted as shown in Figure 14–4(A), fasten a known weight (a straight-pin will suffice) to the anemometer propeller at a fixed distance from the center of the propeller shaft. This will generate a known torque; for example, a 0.1 g weight, placed 10 cm from the center of the shaft, will generate a torque of 1.0 g-cm. If the known torque causes the propeller to rotate downward, approximately 90° [see Figure 14–4(B)], then the known torque is greater than or equal to the starting torque; if the propeller fails to rotate approximately 90°, the known torque is less than the starting torque. By trying different combinations of weight and distance, the starting torque of a particular anemometer can be satisfactorily estimated. Once an estimate of the starting torque has been obtained, the threshold velocity of the anemometer (for horizontal mounting) can be estimated from a graph such as Figure 14–5 (obtained from the manufacturer). If the horizontal threshold velocity is acceptable [<15 m/min (50 fpm), when this technique is used], the anemometer can be used. If the threshold velocity of an anemometer is found to be unacceptably high, the anemometer shall either be replaced or repaired.

BILLING CODE 6560-01-M

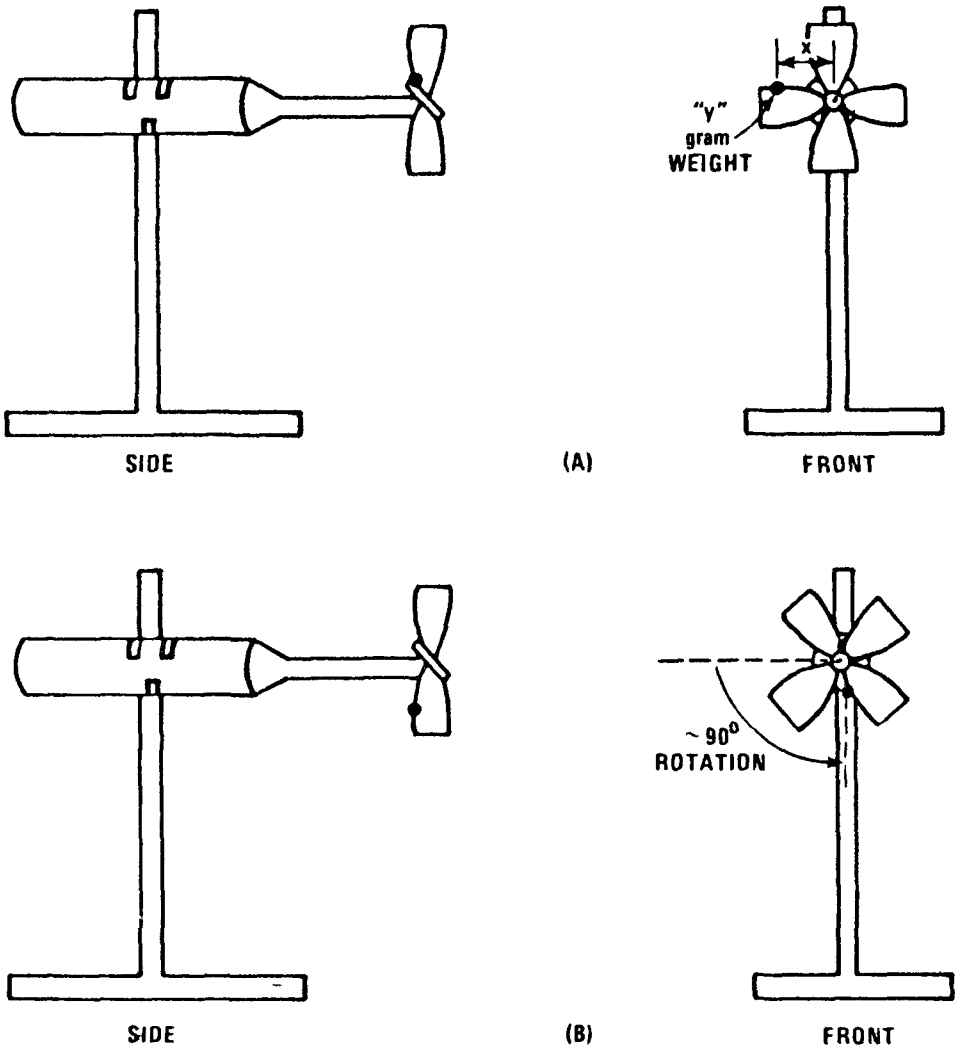


Figure 14-4. Check of anemometer starting torque. A "y" gram weight placed "x" centimeters from center of propeller shaft produces a torque of "xy" g-cm. The minimum torque which produces a 90° (approximately) rotation of the propeller is the "starting torque."

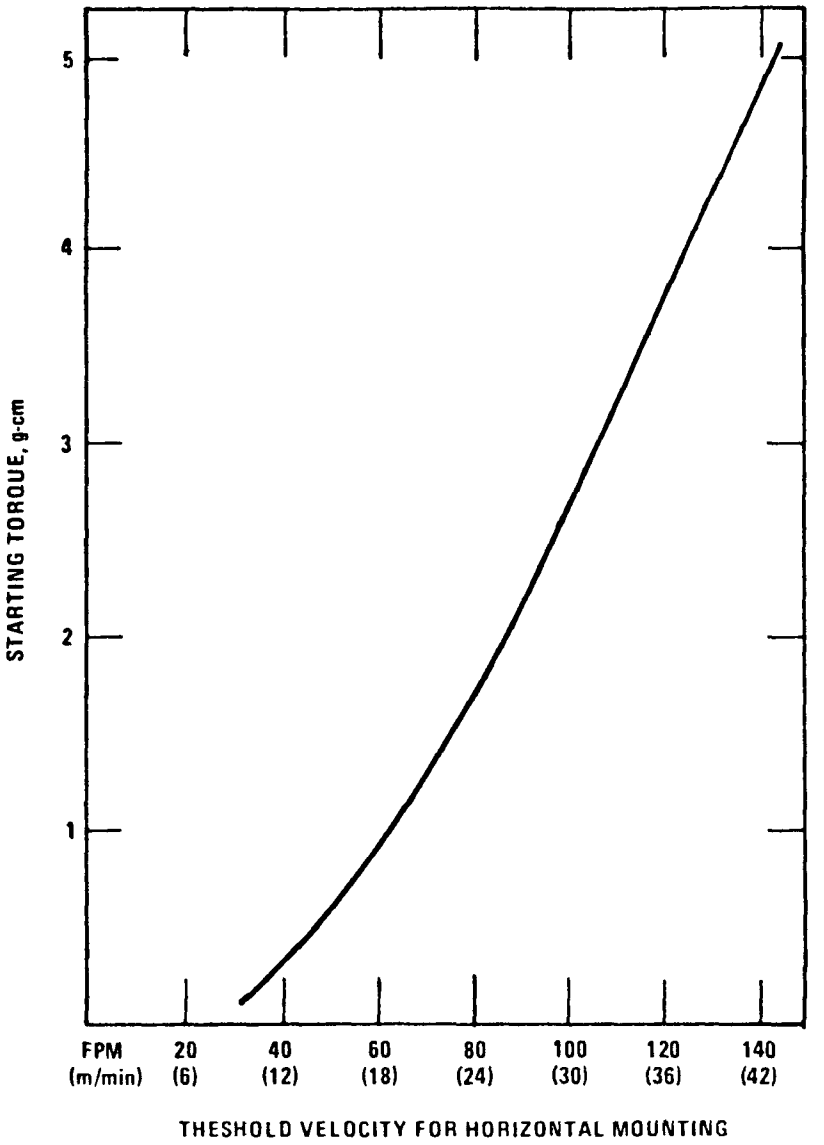


Figure 14-5. Typical curve of starting torque vs horizontal threshold velocity for propeller anemometers. Based on data obtained by R.M. Young Company, May, 1977.

4.1.2 Thermocouple. Check the calibration of the thermocouple-potentiometer system, using the procedures outlined in Section 4.3 of Method 2, at temperatures of 0, 100, and 150°C. If the calibration is off by more than 5°C at any of the temperatures, repair or replace the system; otherwise, the system can be used.

4.1.3 Recorders and/or counters. Check the calibration of each recorder and/or counter (see Section 2.1.3) at a minimum of three points, approximately spanning the expected range of velocities. Use the calibration procedures recommended by the manufacturer, or other suitable procedures (subject to the approval of the Administrator). If a recorder or counter is found to be out of calibration, by an average amount greater than 5 percent for the three calibration points, replace or repair the system; otherwise, the system can be used.

4.1.4 Manifold Intake Nozzles. In order to balance the flow rates in the eight individual nozzles, proceed as follows: Adjust the exhaust fan to draw a volumetric flow rate (refer to Equation 14-1) such that the entrance velocity into each manifold nozzle approximates the average effluent velocity in the roof monitor. Measure the velocity of the air entering each nozzle by inserting a standard pitot tube into a 2.5 cm or less diameter hole (see Figure 14-2) located in the manifold between each blast gate (or valve) and nozzle. Note that a standard pitot tube is used, rather than a type S, to eliminate possible velocity measurement errors due to cross-section blockage in the small (0.13 m diameter) manifold leg ducts. The pitot tube tip shall be positioned at the center of each manifold leg duct. Take care to insure that there is no leakage around the pitot tube, which could affect the indicated velocity in the manifold leg. If the velocity of air being drawn into each nozzle is not the same, open or close each blast gate (or valve) until the velocity in each nozzle is the same. Fasten each blast gate (or valve) so that it will remain in this position and close the pitot port holes. This calibration shall be performed when the manifold system is installed. Alternatively, the manifold may be preassembled and the flow rates balanced on the ground, before being installed.

4.2 Periodical performance checks. Twelve months after their initial installation, check the calibration of the propeller anemometers, thermocouple-potentiometer system, and the recorders and/or counters as in Section 4.1. If the above systems pass the performance checks, (i.e., if no repair or replacement of any component is necessary), continue with the performance checks on a 12-month interval basis. However, if any of the above systems fail the performance checks, repair or replace the system(s) that failed and conduct the periodical performance checks on a 3-month interval basis, until sufficient information (consult with the Administrator) is obtained to establish a modified performance check schedule and calculation procedure.

Note.—If any of the above systems fail the initial performance checks, the data for the past year need not be recalculated.

5. *Procedure.*

5.1 Roof Monitor Velocity Determination.

5.1.1 Velocity estimate(s) for setting isokinetic flow. To assist in setting isokinetic flow in the manifold sample nozzles, the anticipated average velocity in the section of the roof monitor containing the sampling manifold shall be estimated prior to each test run. The tester may use any convenient means to make this estimate (e.g., the velocity indicated by the anemometer in the section of the roof monitor containing the sampling manifold may be continuously monitored during the 24-hour period prior to the test run).

If there is question as to whether a single estimate of average velocity is adequate for an entire test run (e.g., if velocities are anticipated to be significantly different during different potroom operations), the tester may opt to divide the test run into two or more "sub-runs," and to use a different estimated average velocity for each sub-run (see Section 5.3.2.2.)

5.1.2 Velocity determination during a test run. During the actual test run, record the velocity or volumetric flowrate readings of each propeller anemometer in the roof monitor. Readings shall be taken for each anemometer every 15 minutes or at shorter equal time intervals (or continuously).

5.2 Temperature recording. Record the temperature of the roof monitor every 2 hours during the test run.

5.3 Sampling.

5.3.1 Preliminary air flow in duct. During 24 hours preceding the test, turn on the exhaust fan and draw roof monitor air through the manifold duct to condition the ductwork. Adjust the fan to draw a volumetric flow through the duct such that the velocity of gas entering the manifold nozzles approximates the average velocity of the air exiting the roof monitor in the vicinity of the sampling manifold.

5.3.2 Manifold isokinetic sample rate adjustment(s).

5.3.2.1 Initial adjustment. Prior to the test run (or first sub-run, if applicable; see Section 5.1.1 and 5.3.2.2), adjust the fan to provide the necessary volumetric flowrate in the sampling duct, so that air enters the manifold sample nozzles at a velocity equal to the appropriate estimated average velocity determined under Section 5.1.1. Equation 14-1 gives the correct stream velocity needed in the duct at the sampling location, in order for sample gas to be drawn isokinetically into the manifold nozzles. Next, verify that the correct stream velocity has been achieved, by performing a pitot tube traverse of the sample duct (using either a standard or type S pitot tube); use the procedure outlined in Method 2.

$$v_d = \frac{8\,(D_n)^2}{(D_d)^2}\,(v_m)\,\frac{1\ \text{min}}{60\ \text{sec}} \qquad \text{(Equation 14-1)}$$

Where:

v_d = Desired velocity in duct at sampling location, m/sec.

D_n = Diameter of a roof monitor manifold nozzle, m.

D_d = Diameter of duct at sampling location, m.

v_m = Average velocity of the air stream in the roof monitor, m/min, as determined under Section 5.1.1.

5.3.2.2 Adjustments during run. If the test run is divided into two or more "sub-runs" (see Section 5.1.1), additional isokinetic rate adjustment(s) may become necessary during the run. Any such adjustment shall be made just before the start of a sub-run, using the procedure outlined in Section 5.3.2.1 above.

Note.—Isokinetic rate adjustments are not permissible during a sub-run.

5.3.3 Sample train operation. Sample the duct using the standard fluoride train and methods described in Methods 13A and 13B. Determine the number and location of the sampling points in accordance with Method 1. A single train shall be used for the entire sampling run. Alternatively, if two or more sub-runs are performed, a separate train may be used for each sub-run; note, however, that if this option is chosen, the area of the sampling nozzle shall be the same (± 2 percent) for each train. If the test run is divided into sub-runs, a complete traverse of the duct shall be performed during each sub-run.

5.3.4 Time per run. Each test run shall last 8 hours or more; if more than one run is to be performed, all runs shall be of approximately the same (± 10 percent) length. If question exists as to the representativeness of an 8-hour test, a longer period should be selected. Conduct each run during a period when all normal operations are performed underneath the sampling manifold. For most recently-constructed plants, 24 hours are required for all potroom operations and events to occur in the area beneath the sampling manifold. During the test period, all pots in the potroom group shall be operated such that emissions are representative of normal operating conditions in the potroom group.

5.3.5 Sample recovery. Use the sample recovery procedure described in Method 13A or 13B.

5.4 *Analysis.* Use the analysis procedures described in Method 13A or 13B.

6. *Calculations.*

6.1 Isokinetic sampling check.

6.1.1 Calculate the mean velocity (v_m) for the sampling run, as measured by the anemometer in the section of the roof monitor containing the sampling manifold. If two or more sub-runs have been performed, the tester may opt to calculate the mean velocity for each sub-run.

6.1.2 Using Equation 14-1, calculate the expected average velocity (v_d) in the sampling duct, corresponding to each value of v_m obtained under Section 6.1.1.

6.1.3 Calculate the actual average velocity (v_s) in the sampling duct for each run or sub-run, according to Equation 2-9 of Method 2, and using data obtained from Method 13.

6.1.4 Express each value v_s from Section 6.1.3 as a percentage of the corresponding v_d value from Section 6.1.2.

6.1.4.1 If v_s is less than or equal to 120 percent of v_d, the results are acceptable (note that in cases where the above calculations have been performed for each sub-run, the results are acceptable if the average percentage for all sub-runs is less than or equal to 120 percent).

6.1.4.2 If v_s is more than 120 percent of v_d, multiply the reported emission rate by the following factor.

$$1 + \frac{(100\ v_s/v_d) - 120}{200}$$

6.2 Average velocity of roof monitor gases. Calculate the average roof monitor-velocity using all the velocity or volumetric flow readings from Section 5.1.2.

6.3 Roof monitor temperature. Calculate the mean value of the temperatures recorded in Section 5.2.

6.4 Concentration of fluorides in roof monitor air (in mg F/m³).

6.4.1 If a single sampling train was used throughout the run, calculate the average fluoride concentration for the roof monitor using Equation 13A-2 of Method 13A.

6.4.2 If two or more sampling trains were used (i.e., one per sub-run), calculate the average fluoride concentration for the run, as follows:

$$\bar{C}_s = \frac{\sum_{i=1}^{n} (F_t)_i}{\sum_{i=1}^{n} (V_{m(std)})_i} \qquad \text{(Equation 14-2)}$$

Where:

C_s = Average fluoride concentration in roof monitor air, mg F/dscm.

F_t = Total fluoride mass collected during a particular sub-run, mg F (from Equation 13A-1 of Method 13A or Equation 13B-1 of Method 13B).

$V_{m(std)}$ = Total volume of sample gas passing through the dry gas meter during a particular sub-run, dscm (see Equation 5-1 of Method 5).

n = Total number of sub-runs.

6.5 Average volumetric flow from the roof monitor of the potroom(s) (or potroom segment(s)) containing the anemometers is given in Equation 14-3.

$$Q_m = \frac{v_{mt}(A)\ (M_d)\ P_m(293\ ^\circ K)}{(T_m + 273)\ (760\ mm\ Hg)} \qquad \text{(Equation 14-3)}$$

Where:

Q_m = Average volumetric flow from roof monitor at standard conditions on a dry basis, m³/min.

A = Roof monitor open area, m².

v_{mt} = Average velocity of air in the roof monitor, m/min, from Section 6.2.

P_m = Pressure in the roof monitor; equal to barometric pressure for this application, mm Hg.

T_m = Roof monitor temperature, °C, from Section 6.3.

M_d = Mole fraction of dry gas, which is given by:

$$M_d = (1 - B_{ws})$$

Note.—B_{ws} is the proportion by volume of water vapor in the gas stream, from Equation 5-3, Method 5.

7. *Bibliography.*

1. Shigehara, R. T., A guideline for Evaluating Compliance Test Results (Isokinetic Sampling Rate Criterion). U.S. Environmental Protection Agency, Emission Measurement Branch, Research Triangle Park, North Carolina, August 1977.

[FR Doc 80-19516 Filed 6-27-80 8:45 am]

BILLING CODE 6560-01-M

SECTION V

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Proposed Amendments

V. PROPOSED AMENDMENTS

Subpart	
A	General Provisions Definitions
D	Fossil-Fuel-Fired Industrial Steam Generators Advance Notice of Proposed Rulemaking
E	Incinerators Review of Standards
F	Portland Cement Plants Review of Standards
G	Nitric Acid Plants Review of Standards
H	Sulfuric Acid Plants Review of Standards
J	Petroleum Refinery Review of Standards Clarification of Definition
L	Secondary Lead Smelters Review of Standards
M	Secondary Brass and Bronze Ingot Production Review of Standards
N	Iron and Steel Plants, Basic Oxygen Furnace Review of Standards
O	Sewage Treatment Plants Review of Standards
AA	Electric Arc Furnaces (Steel Industry) Review of Standards
CC	Glass Manufacturing Plants Proposed Standards

Subpart

FF Stationary Internal Combustion Engines
Proposed Standards

JJ Organic Solvent Cleaners
Proposed Standards

KK Lead-Acid Battery Manufacture
Proposed Standards

MM Automobile and Light Duty Truck Surface Coating Operations
Proposed Standards

NN Phosphate Rock Plants
Proposed Standards

PP Ammonium Sulfate Manufacture
Proposed Standards

Appendix A Method 12 - Inorganic Lead Emissions from Stationary Sources, see Subpart KK

Method 23 - Halogenated Organics from Stationary Sources, see Subpart JJ

Method 24 (Candidate 1) - Volatile Content (as Carbon) of Paint, Varnish, Lacquer, or Related Products, see Subpart MM

Method 24 (Candidate 2) - Volatile Organic Compound Content (as Mass) of Paint, Varnish, Lacquer, or Related Products, see Subpart MM

Method 25 - Total Gaseous Nonmethane Organic Emissions as Carbon: Manual Sampling and Analysis Procedure, see Subpart MM

Appendix B Performance Specification 1 - Opacity Continuous Monitoring Systems in Stationary Sources

Performance Specification 2 - SO_2 and NO_x Continuous Monitoring Systems in Stationary Sources

Performance Specification 3 - CO_2 and O_2 Continuous Monitors in Stationary Sources

Performance Specification 4 - Carbon Monoxide Continuous Monitoring Systems in Stationary Sources

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

GENERAL PROVISIONS

SUBPART A

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Parts 60 and 61]

[FRL 1085-1]

Standards of Performance for New Stationary Sources and National Emission Standards for Hazardous Air Pollutants; Definition of "Commenced"

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed Rule.

SUMMARY: This action proposes an amendment to the definition of "commenced" as used under 40 CFR Parts 60 and 61 (standards of performance for new stationary sources and national emission standards for hazardous air pollutants). The legislative history of the Clean Air Act Amendments of 1977 indicates that EPA should revise the definition of "commenced" to be consistent with the definition contained in the prevention of significant deterioration requirements of the Act. This proposal would effect that revision.

DATES: Comments must be received on or before July 30, 1979.

ADDRESSES: Comments should be submitted to Jack R. Farmer, Chief, Standards Development Branch (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711. Public comments received may be inspected and copied at the Public Information Reference Unit (EPA Library) Room 2922, 401 M Street, S.W., Washington, D.C.

FOR FURTHER INFORMATION CONTACT: Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number 919-541-5271.

SUPPLEMENTARY INFORMATION: For many of EPA's regulations, it is important to determine whether a facility has commenced construction by a certain date. For instance, as provided under section 111 of the Clean Air Act, facilities for which construction is commenced on or after the date of proposal of standards of performance are covered by the promulgated standards. The definition of "commenced" is thus one factor determining the scope of coverage of the proposed standards. "Commenced" is currently defined under 40 CFR Part 60 as meaning:

> * * * with respect to the definition of "new source" in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

A similar definition (minus the reference to section 111(a)(2)) is used under 40 CFR Part 61. As provided under section 112 of the Act, facilities which commence construction after the date of proposal of a national emission standard for a hazardous air pollutant are subject to different compliance schedule requirements than those facilities which commence before proposal.

The Clean Air Act Amendments of 1977 include a definition of "commenced" under Part C—Prevention of Significant Deterioration (PSD) of Air Quality. The PSD definition of "commenced" requires an owner or operator to obtain all necessary preconstruction permits and either (1) to have begun physical on-site construction or (2) to have entered into a binding agreement with significant cancellation penalties before a project is considered to have "commenced."

On November 1, 1977, Congress adopted some technical and conforming amendments to the Clean Air Act Amendments of 1977. Representative Paul Rogers presented a Summary and Statement of Intent which stated:

> In no event is there any intent to inhibit or prevent the Agency from revising its existing regulations to conform with the requirements of section 165. In fact, the Agency should do so as soon as possible. It is also expected that the Agency will act as soon as possible to revise its new source performance standards and the definition of 'commenced construction' for the purpose of those revised standards to conform to the definition contained in part C.

In view of this background, EPA has decided to make the definition of "commenced" as used under Part 60 consistent with the definitions used under the PSD requirement of Parts 51 and 52. Even though Congress did not specify any changes to the definition under Part 61, it is reasonable to also change that definition to be consistent with those under Parts 60, 51, and 52. The manner in which the definition would be interpreted is expressed in the preamble to the PSD regulations 43 FR 26395-26396. For complete consistency with the Clean Air Act and Parts 51 and 52, a new definition of "necessary preconstruction approvals or permits" has also been added.

EPA does not intend that sources would be brought under the standards by the revised definitions that would not have been covered by the existing definitions. The revised definitions would be effective 30 days after promulgation of the final definitions. Facilities which have commenced construction under the present definitions before the effective date of the revised definitions would be considered to have commenced construction under the revised definitions, i.e., the revised definitions would not be applied retroactively. Note, however, that under the PSD regulations, sources could be required to apply control technology capable of meeting the most recent standard of performance even though that standard is not applicable, because the applicable standard of performance requirements are only the minimum criteria for granting a PSD permit.

During the public comment period, comments are invited regarding the impact of the revised definition. In particular, comments are invited regarding actual compliance problems which may occur because of this revision.

Dated: May 23, 1979.

Douglas M. Costle,

Administrator.

It is proposed to amend 40 CFR Parts 60 and 61 by amending §§ 60.2(i) and 61.02(d) and by adding §§ 60.2(cc) and 61.02(q) as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart A—General Provisions

§ 60.2 Definitions.

* * * * *

(i) "Commenced" means, with respect to the definition of "new source" in section 111(a)(2) of the Act, either that:

(1) An owner or operator has obtained all necessary preconstruction approvals or permits and either has:

(i) Begun, or caused to begin, a continuous program of physical on-site construction of the facility to be completed within a reasonable time; or

(ii) Entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed within a reasonable time, or

(2) An owner or operator had commenced construction before (effective date of this definition) under

the definition of "commenced" in effect before (effective date of this definition).

* * * * *

(cc) "Necessary preconstruction approvals or permits" means those permits or approvals required under Federal air quality control laws and regulations and those air quality control laws and regulations which are part of the applicable State implementation plan.

(Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a))).

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

FOSSIL FUEL-FIRED STEAM GENERATORS

SUBPART D

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 60]

[FRL 1094-6]

Standards of Performance for New Stationary Sources; Fossil-Fuel-Fired Industrial Steam Generators

AGENCY: Environmental Protection Agency (EPA).

ACTION: Advance Notice of Proposed Rulemaking.

SUMMARY: EPA seeks comments on its plan to develop and implement new source performance standards for air pollutants from fossil-fuel-fired industrial (non-utility) steam generators. The Clean Air Act, as amended, August 1977, requires the EPA to develop standards for categories of fossil-fuel-fired stationary sources. The standards will require application of the best systems of emission reduction for particulates, sulfur dioxide, and nitrogen oxides to new industrial steam generators.

DATES: Comments must be received on or before August 27, 1979.

ADDRESS: Comments should be submitted to the Central Docket Section (A-130), United States Environmental Protection Agency, 401 M Street, S.W. Washington, D.C. 20460, ATTN: Docket No. A79-02.

FOR FURTHER INFORMATION CONTACT: Stanley T. Cuffe, Chief, Industrial Studies Branch (MD-13), Emission Standards and Engineering Division, United States Environmental Protection Agency, Research Triangle Park, North Carolina 27711, (919) 541-5295.

SUPPLEMENTARY INFORMATION: In December 1971, pursuant to Section 111 of the Clean Air Act, the Administrator promulgated standards of performance for particulate, sulfur dioxide, and oxides of nitrogen from new or modified fossil fuel fired steam generators with greater than 250 million BTU/hour heat input (40 CFR 60.60). Since that time, the technology for controlling these emissions has been improved. In August 1977, Congress adopted amendments to the Clean Air Act which specified that the Environmental Protection Agency develop standards of performance for categories of fossil-fuel-fired stationary sources. The standards are to establish allowable emission limitations and require the achievement of a percentage reduction in the emissions. EPA is required to consider a broad range of issues in promulgating or revising a standard issued under Section 111 of the Clean Air Act.

Pursuant to the requirements of the Act, EPA developed and proposed on September 19, 1978, a revised standard applicable to fossil-fuel-fired utility boilers with heat input greater than 250 MM BTU/hour.

Development of Industrial Boiler Standard

In June 1978, the Agency initiated a program to develop standards which would apply to all sizes and categories of industrial (non-utility) fossil-fuel-fired steam generators. In this program, the Agency is studying the technological, economic, and other information needed to establish a basis for standards for particulate, sulfur dioxide and oxides of nitrogen emissions from fossil-fuel-fired steam generators. Pertinent information is being gathered on eight technologies for reducing boiler emissions: oil cleaning and existing clean oil, coal cleaning and existing clean coal; synthetic fuels; fluidized bed combustion; particulate control; flue gas desulfurization; NOx combustion modifications; and NOx flue gas treatment. The studies for each technology will discuss the characteristics, emission reduction methods and potential control costs, energy and environmental considerations and emission test data. A status report on the studies was presented to the National Air Pollution Control Techniques Advisory Committee (NAPCTAC), on January 11, 1979. Future presentations to the NAPCTAC will be announced in the **Federal Register.** The final technological and economic documentation necessary to support the standards is scheduled for completion by June 1980. Interested persons are invited to participate in Agency efforts by submitting written data, opinions, or arguments as they may desire. The Agency is specifically interested in information on the following subjects.

a. Should one standard be proposed for all industrial applications or should standards be set for separate industrial categories?

b. Should a single standard be proposed for all sizes of industrial boilers or should several standards be proposed for various boiler size categories?

c. Should emerging technologies such as solvent refined coal, fluidized bed combustion, and synthetic natural gas be exempt from industrial boiler standards, should they have separate standards, or should they be required to meet the same standards as conventional boilers burning natural fuels?

d. Will enforcement of standards at cogeneration facilities present special problems which should be considered?

e. How prevalent is the use of lignite and anthracite coal in industrial boilers?

f. Are there special problems which should be considered when controlling particulate, SO_x, or NO_x emissions from combustion of lignite or anthracite coals?

Dated: June 13, 1979.

Douglas M. Costle,

Administrator.

[FR Doc. 79-20056 Filed 6-27-79; 8:45 am]

BILLING CODE 6560-01-M

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

INCINERATORS

SUBPART E

40 CFR Part 60

[FRL 1310-2]

Standards of Performance for New Stationary Sources: Incinerators; Review of Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Review of standards.

SUMMARY: EPA has reviewed its standard of performance for municipal incinerators (40 CFR 60.50, Subpart E). The review is required under the Clean Air Act, as amended August 1977. The purpose of this notice is to announce EPA's intent to investigate the establishment of a revised standard which would be consistent with the performance capabilities of demonstrated best available control technology and which would include a limitation on the opacity of emissions

DATES: Comments must be received by January 28, 1980.

ADDRESS: Send comments to. Central Docket Section (A-130), U.S. Environmental Protection Agency, 401 M Street SW., Washington, D.C. 20460, Attention: Docket A-79-18. Comments should be submitted in duplicate if possible.

FOR FURTHER INFORMATION CONTACT: Mr. Robert Ajax, Telephone: (919) 541-5271. The document "A Review of Standards of Performance for New Stationary Sources—Incinerators" (EPA-450/3-79-009) is available upon request from Mr. Robert Ajax (MD-13), Emission Standards and Engineering Division, U.S. Environmental Protection Agency, Research Triangle Park, N.C 27711.

SUPPLEMENTARY INFORMATION:

Background

New Source Performance Standards (NSPS) for incinerators were promulgated by the Environmental Protection Agency on December 23, 1971 (40 CFR 60.50, Subpart E). These standards regulate the emission of particulate matter to the atmosphere from municipal solid waste incinerators having charging rates greater than 45 Mg (50 tons) per day. These regulations apply to any affected facility which commenced construction or modification after August 17, 1971

The Clean Air Act Amendments of 1977 require that the Administrator of the EPA review and, if appropriate, revise established standards of performance for new stationary sources at least every 4 years [Section 111(b)(1)(B)]. Following adoption of the Amendments, EPA contracted with the MITRE Corporation to undertake a review of the municipal incinerator industry and the current standard. The MITRE review was completed in March 1979. This notice announces EPA's decision regarding the need for revision of the standard. Comments on the results of this review and on EPA's decision are invited.

Findings

Industry Status: In 1972 there were 193 incinerator plants operating in the U.S. By 1977 this number had decreased to 103 plants which include a total of 252 furnaces and a total solid waste disposal capacity of about 36,000 Mg/day (40,000 tons/day). The estimated national particulate emissions from municipal incineration in 1975 were between 60,000 and 100,000 tons or between 0.4 and 0.6 percent of all particulate emissions in the U.S.

Since 1971 five new incinerator facilities involving a total of eight new furnaces with a combined capacity of 2,700 Mg/day (2,970 tons/day) have become operational. In 1978, 17 cities were identified where new incinerators are planned or under construction. Both existing units and the units which are planned or under construction are concentrated primarily in the Northeast and Midwest.

Coincineration: A factor having an increasingly important impact on the use of incineration as a waste disposal process is the increasing cost of energy and the relatively new concept of resource recovery not only for recycling of material but also for utilization of the energy content of solid waste as a processed fuel source. A recent survey indicates that there are at least 28 resource recovery systems in operation, under construction, or in the final contract stage. Total capacity of these operations will be about 27,000 Mg/day (30,000 tons/day), or about three-fourths of the current installed incinerator capacity. For the most part, these systems are characterized by substantial processing of solid waste into usable recycled material and a homogenous fuel.

The processing of solid waste prior to combustion is a growing trend that has implications in the definition of incineration and the applicability of the standard. Refuse derived fuel (RDF) may be used in an industrial or utility boiler which may or may not be located at the new solid waste processing center. Similarly, RDF may be used to provide fuel for incinerating sewage sludge in a fluidized bed reactor. Such coincineration of municipal solid waste and sewage sludge has been practiced in Europe for several years and on a limited scale in the U.S. Where energy resources are scarce and land disposal is economically or technically unfeasible, the recovery of the heat content of dewatered sludge as an energy source will become more desirable. Due to the institutional commonality of these wastes and advances in the preincineration processing of municipal refuse to a waste fuel, many communities may find joint incineration in energy recovery incinerators an economically attractive alternative to their waste disposal problems.

Coincineration of municipal solid waste and sewage sludge as described above is not explicitly covered in 40 CFR 60. The particulate standard for municipal solid waste described in Subpart E (0.18 grams/dscm or 0.08 grains/dscf at 12 percent CO_2) applies to the incineration of municipal solid waste in furnaces with a capacity of at least 45 Mg/day (50 tons/day). Subpart 0, the particulate standard for sewage sludge incineration (0.65 grams/kg dry sludge input or 1.3 lb/ton dry sludge), applies to any incinerator that burns sewage sludge with the exception of small communities practicing coincineration. When coincineration is practiced, determination of the applicability of the two standards is made by EPA's Office of Enforcement according to policies which are described in the information document identified at the beginning of this notice. Such determinations are not straight forward, however, due to the differing form of the two standards and the relative stringency which, in terms of particulate matter concentration or grain loading, differs by a factor of more than two.

Particulate Matter Emissions and Control Technology

Control systems on municipal incinerators have evolved from the use of simple settling chambers which remove large particles, to the use of electrostatic precipitators (ESPs) that remove up to 99 percent of all particulate matter. Many of the incinerators constructed prior to 1971 utilized mechanical cyclone collectors with removal efficiencies in the range of 60 to 80 percent. Various scrubber techniques including the submerged entry of gases, the spray wetted-wall cyclone, and the venturi scrubber were also employed. High efficiency electrostatic precipitators were utilized in a limited number of cases.

Since the adoption in 1971 of the new source performance standard, the control device which has been most widely used and which has been most

effective is the electrostatic precipitator A limited number of venturi scrubbers and, in one case, a fabric filter have also been employed.

In this review of the standard, a total of 19 emission tests were identified which had been performed on 14 incinerators. The control equipment on these incinerators was designed to comply with the Federal new source performance standard for particulate matter or State or local standards which are as stringent or more stringent than the NSPS. The emission tests in each case were performed with EPA Method 5. A summary of the test results is provided in Table 1.

Table 1.—*Municipal Incinerator Test Results*

State	City/name	(Tons/day)	Control	Test results	
				(Gr/dscf at 12 pct CO_2)	Year
Massachusetts	E Bridgewater	150	F F	0 024	1975
Massachusetts	Saugus	600	ESP	0 049	1976
Tennessee	Nashville	360	ESP	0 018	1976
Virginia	Norfolk (Navy)	280	ESP	0 05	1976
Utah	Ogden-3	150	ESP	0 045	1974
District of Columbia	Washington	200	ESP	0 040/0 06	1973
Illinois	Chicago NW	400	ESP	0 030/0 050	1971/75
Maryland	Baltimore No 4	300	ESP	0 025	1976
Pennsylvania	EC Philadelphia.	300	ESP	0 047	1977
Pennsylvania	NW Philadelphia	300	ESP	0 048	1976
Illinois	Calumet	200	VS (15)	0 046/0 049	1974
Kentucky	Louisville	200	VS (15-18)	0 05/0 06	1976
				0 11	1977
Wisconsin	Sheboygan Falls	30-90	S (7-8)	0 416	1976
Rhode Island	Pawtucket	200	VS (35-40)	0 0775	1978

The results shown in Table 1 indicate that ESP control technology is capable of limiting emissions to the values well below the 0.18 g/dscm (0.08 gr/dscf) level at 12 percent CO_2. Specifically, the results from 11 tests performed at 9 facilities employing electrostatic precipitators showed results ranging from 041 to 0.14 g.dscm (0.018 to 0.06 gr/dscf) at 12 percent CO_2; 10 of the 11 were below 0.114 g/dscm (0.05 gr/dscf) The Baltimore Number 4 incinerator emission control system meets the strict Maryland standard for incinerators of 0.07 g/dscm (0.03 gr/dscf) at 12 percent CO_2. Similarly, the Saugus, Massachusetts, facility was designed for the State standard of 0.11 g/dscm (0 05 gr/dscf) at 12 percent CO_2 and was successfully tested at this level of compliance.

The use of scrubbers on municipal incinerators has met with mixed results and an overall difficulty in complying with the particulate emission standard Although the data obtained from five tests at three venturi scrubber-controlled sources ranged from 0.015 to 0.166 g/dscm (0.046 to 0.0775 gr/dscf), the scrubber performance results, which are discussed in more detail in the information document, indicate that venturi scrubbers for control of municipal waste particulate emissions may involve considerable risk of nonattainment of the current NSPS. The Pawtucket facility venturi scrubber, for example, operates at pressure drops higher than the original design to barely meet the standard of 0.18 g/dscm (0.08 gr/dscf) at 12 percent CO_2.

The Sheboygan Falls, Wisconsin, incinerator utilizes a spray chamber with baffles. Although reportedly designed to meet a 0.08 gr/dscf standard, this type of control technology would not normally be expected to exhibit the control efficiency necessary to obtain the standard.

Since 1971, only the East Bridgewater, Massachusetts, facility has been tested with a fabric filter control device. In 1975, that facility tested at 0.054 g/dscm (0.024 gr/dscf) at 12 percent CO_2, well below the Massachusetts standard of 0.11 g/dscm (0.05 gr/dscf) at 12 percent CO_2. However, problems of bag and baghouse corrosion and periodic high opacity observations have persisted

Currently, Framingham, Massachusetts, is the only other municipal incinerator facility with a fabric filter control system. The specially coated bags are designed to prevent deterioration and to achieve 0.07 g/dscm (0.03 gr/dscf) at 12 percent CO_2.

Gaseous and Trace Metal Emissions

Gaseous and trace metal emissions are not specifically controlled under the present NSPS although the incinerator and the particulate matter control equipment do limit such emissions. Among possible gaseous emissions, the potential for high levels of hydrochloric acid (HCL) from the increased incineration of polyvinyl chlorides has received particular attention. Similarly, lead and cadmium have been subject to several studies. Cadmium emissions are reported to represent approximately 0.2 percent of all particulate emissions and about 0.4 percent of emissions less than 2 microns. Lead concentrations are reported to represent about 4 percent of all particulate matter and 11 percent of respirable particulates emitted from the scrubber. Emission factors are 9×10^{-1} kg/Mg (18×10^{-1} lb/ton) refuse for cadmium and 1.9×10^{-1} kg/Mg (3.8×10^{-1} lb/ton) refuse for lead.

In this review of the current NSPS no new findings were identified which indicate the need for a specific, nationally applicable limitation on the gaseous or trace metal emissions. There is, however, currently a program underway within EPA to independently look at the need to regulate cadmium from incinerators and other sources. Separate documents have been prepared which examine emissions, resulting atmospheric concentrations, and population exposure. These documents are part of an overall EPA program to satisfy requirements of the 1977 Clean Air Act to evaluate the need to regulate emissions of cadmium to the air.

Opacity

The current NSPS does not contain a standard for opacity because testing of a limited number of incinerators priot to promulgation of the standard in 1971 did not indicate a consistent relationship between emission opacity and particulate mass concentrations. However, a survey of current State regulations shows that every State has an opacity standard for new incinerators of 20 percent or stricter except Illinois (30 percent), Indiana (40 percent), and Delaware (no standard) Maryland has a "no visible emissions" standard and the District of Columbia has a new source ban on the incineration of municipal waste. However, data were not found in this review of the NSPS to determine whether sources are consistently in compliance with these limits.

Conclusions

Based upon a review of the current NSPS and other available information as summarized above, EPA concludes that there is a need to undertake a program to revise the standard. This program, which is expected to begin in FY 1980, will be directed toward:

(1) Investigation of a more restrictive particulate matter limitation consistent with the capabilities of the best available technology. This is based upon the available data which indicate that the capability of electrostatic precipitators applied to incinerators has improved measurably since the standard was developed in 1971. This investigation will include analysis of the costs associated with a more restrictive standard.

(2) Establishment of an opacity standard. Such a standard is considered important by EPA as a means for assessing proper operation and maintenance of particulate matter control equipment and is included in most of the Agency's particulate matter NSPS. Although a relationship between particulate mass and opacity was not established when the standard was adopted in 1971, the additional number of well controlled plants which are now in operation and the widespread existence of State opacity limits are expected to provide a basis for estalishment of an opacity standard. Consistent with EPA policy, such a standard would not be more restrictive than the particulate mass standard.

(3) Establishment of a consistent basis for the limitation of particulate emissions from differing combustion devices independent of the fuel or waste material being fired. While a single standard is probably not possible, there is a need to investigate the possibility of expressing standards for sludge incinerators, and municipal incinerators on a common basis, and of making the standards more uniform. To do so, EPA plans to closely coordinate the development of the industrial and waste-fired boiler standards which are now underway, and the planned revision of the sewage sludge incinerator standard and the municipal incinerator standard.

(4) In addition, if the need to reduce cadmium emissions is indicated as a result of the EPA program noted above, appropriate action will be taken to limit cadmium emissions.

Public Participation

All interested persons are invited to comment on this review, the conclusions and EPA's planned action.

Dated November 16, 1979.

Barbara Blum,

Acting Administrator

[FR Doc 79-36474 Filed 11-26-79 8 45 am]

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

PORTLAND CEMENT PLANTS

SUBPART F

40 CFR Part 60

Standards of Performance for New Stationary Sources: Portland Cement Plants; Review of Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Review of Standards.

SUMMARY: EPA has reviewed the standards of performance for portland cement plants (40 CFR 60.60). The review is required under the Clean Air Act, as amended August 1977. The purpose of this notice is to announce that, based on an assessment of the industry, applicable control technology, and results of performance tests conducted pursuant to the standard, EPA has determined that no revision to the particulate emission limitation is needed but that the standard should be revised to require continuous opacity monitoring.

DATES: Comments must be received by December 21, 1979.

ADDRESS: Comments should be submitted to the Central Docket Section (A-130), U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460, Attention: Docket No. A-79-19.

The document, "A Review of Standards of Performance for New Stationary Sources—Portland Cement Industry" (EPA-450/3-79-012), is available upon request from Mr. Robert Ajax (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

FOR FURTHER INFORMATION CONTACT: Mr. Robert Ajax, telephone: (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Background

On August 17, 1971, the Environmental Protection Agency proposed a standard under Section 111 of the Clean Air Act to control particulate matter emissions from portland cement plants. The standard, promulgated on December 23, 1971, applies to any facility constructed or modified after August 17, 1971, which manufactures portland cement by either the wet or dry process. Specific affected facilities are the: kiln, clinker cooler, raw mill system, finish mill system, raw mill dryer, raw material storage, clinker storage, finished product storage, conveyor transfer points, bagging, and bulk loading and unloading and unloading systems.

The standard prohibits the discharge into the atmosphere from any kiln any gases which:

1. Contain particulate matter in excess of 0.15 kg/Mg (0.30 lb/ton) feed to the kiln, or
2. Exhibit greater than 20 percent opacity.

The standard prohibits the discharge into the atmosphere from any clinker cooler any gases which:

1. Contain particulate matter in excess of 0.050 kg/Mg (0.10 li/ton) feed (dry basis) to the kiln, or
2. Exhibit 10 percent opacity or greater.

The standard prohibits the discharge into the atmosphere from any affected facility other than the kiln and clinker cooler any gases which exhibit 10 percent opacity, or greater.

The Clean Air Act Amendments of 1977 require that the Administrator of the EPA review and, if appropriate, revise established standards of performance for new stationary sources at least every 4 years [Section 111(b)(1)(B)]. This notice announces that EPA has undertaken a review of the standard of performance for portland cement plants. As a result of this review, EPA has concluded that the present particulate emission limit is appropriate, and does not need revision. However, a provision to require opacity monitoring should be added. In addition, EPA is, however, planning to undertake a program, in its Office of Research and Development, to investigate and demonstrate methods such as combustion modifications which could reduce NO_x emissions from combustion used in process sources such as cement plants. Positive results from this program would form the basis for a possible revision to the standard in 1982 or 1983. Comments on these findings and plans are invited.

Findings

Industry Status

Capacity. There are currently 53 cement companies producing portland cement in the U.S. The 53 companies operate 158 cement plants throughout the U.S. with single plant capacity ranging from 50,000 Mg to 2,161,000 Mg per year. The industry also includes 8 plants with only clinker grinding facilities which use either an imported or domestic clinker as feed material. Cement plants are found in nearly every State because of the high cost of transportation. The actual clinker capacity of these plants is also distributed throughout the U.S., although some regions have little capacity due to a lack of demand; and although many areas of the Country are presently experiencing cement shortages and delays, announced capacity increases in these areas are still small.

Energy Considerations. The portland cement industry is very energy intensive with energy costs accounting for approximately 40 percent of the cost of cement. Accordingly, significant emphasis in the industry is on increasing energy efficiency. For this reason, almost all new and planned construction will use the dry process which can be twice as energy efficient as the wet process. Additional savings can be realized by using preheaters, especially suspension preheaters.

These process changes have both positive and negative effects on particulate emissions. The replacement of wet process units with dry process units increases potential emissions, particularly in the grinding, mixing, blending, storage, and feeding of raw materials to the kiln. The suspension preheater, on the other hand, tends to decrease particulate emissions due to its multicyclone construction. It also ensures more thorough contact of the kiln exhaust gases with the feed material which may increase sorption of sulfur oxide from the exhaust on the feed.

Economic Considerations. Almost all cement produced is utilized by the construction industry. As a result, the production of cement follows the cyclical pattern of the construction industry. Relatively high cement production has occurred during periods of growth in new home and other construction markets, and production has decreased in such periods of recession as occurred in 1973-1975.

In contrast, over the short term, production capacity has not closely paralleled actual production. This is due apparently to the lead time required to add capacity, to the difficulty in accurately predicting future demand, and to economic and other factors including the effect of pollution control requirements on the closure of old, marginal plants.

An examination of production and capacity over the past 10 years suggests the difficulty which the industry has experienced in attempting to meet demand while avoiding excess capacity. In the early 1970's, utilization of production capacity was greater than 90 percent. However, wage and price controls were in effect from 1971 to 1973 during which time the industry experienced its lowest profit margin since the 1930's. New plant construction was postponed while some older plants were being closed. As a result, regional cement shortages occurred in 1972-1973. When price controls were removed in

1973, the price of cement jumped 14 percent and some new capacity construction was begun. Shortly thereafter, the Country entered a recession and cement production fell to 70 percent of capacity.

The cyclic occurrence of high demand exceeding capacity has been evidenced again in the past several years. The rapid growth in the construction industry since 1975 has increased the demand for cement and parts of the U.S. have seen shortages, particularly in the West. At the same time, the industry has not rapidly added new capacity, although the Bureau of Mines projects high demand in the early 1980's.

In considering whether pollution control costs influenced the recent lag in capacity, the Council on Wage and Price Stability concluded that:

> ... the added pollution control costs do change the way a firm would consider a new investment decision by making larger price increases necessary for the expenditures to be committed. this does not mean that the imposition of these controls has necessarily cause any reduction in new capacity expenditures in the cement industry. However, this analysis does leave open the possibility that an investment decision could be changed for a marginal plant because of pollution control costs (particularly a plant selling cement for $40 per ton and using a 12 percent rate of return). (*Prices and Capacity Expansion in the Cement Industry*, Council on Wage and Price Stability, Washington, D.C., 1977.)

Since cement is already selling for as high as $53 per ton on the West Coast, it is very likely that capital investment will not be stifled by pollution control expenditures.

Emission Control Status

Fifty-one cement kilns and clinker coolers have been identified which are operating and are subject to the new source performance standard. Of these, 49 are in compliance with 0.15 kg/Mg kiln feed (kiln) and 0.05 kg/Mg kiln feed, (cooler) emission limits. One completed kiln has only recently been tested and data are not available; and one facility has notified its State authority that it cannot meet the standards. Also, five cement kilns potentially subject to the standard were identified for which data were not available. The number of sources with other NSPS-affected facilities was not determined, although there are none reported that are not in compliance with the applicable 10 percent opacity standard.

For the 29 kilns and 20 clinker coolers which were in compliance, the kiln test results averaged 0.073 kg/Mg and ranged from a high of 0.142kg/Mg feed to a low of 0.013kg/Mg feed. The range for kilns with emissions controlled by ESP is 0.142 to 0.020 kg/Mg, and for kilns with fabric filter baghouses the range is 0.132 to 0.013 kg/Mg dry kiln feed. The data indicate that neither the ESP nor the baghouse is significantly better at controlling cement kiln particulate matter emissions.

Cement plant clinker coolers have been tested at emission levels ranging from a high of 0.061 kg/Mg to a low of 0.005 kg/Mg dry kiln feed with a mean of 0.024 kg/Mg. Compliance test data on a single wet scrubber show emissions near the mean emission level for fabric filter baghouse controls (0.022 kg/Mg). Data for affected facilities using gravel bed filters indicate a mean emission level of 0.034 kg/Mg dry feed (0.023–0.045kg/Mg).

The compliance test data were analyzed to determine if the type of control technology, the process type (i.e., wet or dry), or interaction of process type and control technology affected the ability to control the emission of particulate matter from portland cement kilns or clinker coolers. This analysis indicates that no control technology in use today is more effective for controlling particulate matter emissions. Although comparison of mean values indicates that the possibility that emissions from dry process kilns are controlled slightly more effectively than wet process kilns, the difference is not statistically significant.

Nitrogen Oxide Emissions

Cement kilns are a very large and presently unregulated source of nitrogen oxides (NO_x) emissions. Based upon estimated NO_x emissions of 1.3 kg/Mg of cement produced and 71.4 million Mg of portland cement produced in 1977, an estimated 93,000 Mg of NO_x were emitted by portland cement plants that year. The main factors that result in the production of NO_x are the flame and kiln temperature, the residence time that combustion gases remain at this temperature, the rate of cooling of these gases, and the quantity of excess air in the flame. Control of these factors may permit the operator to sharply reduce the emission of NO_x, but such practices have not been demonstrated in cement plants for NO_x emissions.

Opacity Monitoring

When the NSPS for portland cement plants was established in 1971 no provisions were included to require continuous monitoring of opacity. This was, in part, because the presence of water vapor in the exhaust gases from wet-process facilities would affect monitor accuracy. In addition, monitoring systems had not been demonstrated at baghouse controlled facilities where stack gases are emitted from roof monitors or multiple stub stacks. However, since the standard was adopted, a monitoring system has been demonstrated at a steel plant utilizing baghouse controls and stub stacks.

Conclusions

On the basis of the findings which are summarized above, EPA has concluded that the current particulate matter standards are appropriate and effective and that no revision is needed. While the compliance test data do show that the mean results are well below the standards, the range of data suggest that the standard is set at a level which reflects the performance of the best systems of emission reduction.

However, it is concluded that the standard should be revised to include provisions requiring the continuous monitoring of opacity. This conclusion is based upon the demonstration of opacity monitors on baghouse stub stacks and on the shift in the portland cement industry toward the dry process, as well as EPA's belief that continuous monitoring represents an important and effective means for assuring proper operation and maintenance of particulate matter control equipment. Adoption of any opacity monitoring requirement will be preceded by a proposal and the opportunity for public comment. The Agency expects to undertake development and to propose this revision during 1980.

It is also concluded that the lack of demonstrated control technology and an emission limitation for NO_x is an important deficiency. The Agency is therefore planning to evaluate, develop, and demonstrate means for limiting NO_x emissions. This program, which will include other industrial process fuel users, will be aimed at transferring technology being employed to control NO_x emissions from steam generators If this proves successful, the results will be used as a basis for development of NO_x standards.

Public Participation

All interested persons are invited to comment on this review, the conclusions, and EPA's planned action.

Dated October 16, 1979

Douglas M. Costle,

Administrator

[FR Doc 79-32586 Filed 10-19-79 8 45 am]

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

NITRIC ACID PLANTS

SUBPART G

[40 CFR Part 60]

[FRL 1095-1]

Review of Standards of Performance for New Stationary Sources: Nitric Acid Plants

AGENCY: Environmental Protection Agency (EPA).

ACTION: Review of standards.

SUMMARY: EPA has reviewed the standard of performance for nitric acid plants. The review is required under the Clean Air Act, as amended August 1977. The purpose of this notice is to announce EPA's intent not to undertake revision of the standards at this time.

DATES: Comments must be received on or before August 20, 1979.

ADDRESSES: Send comments to the Central Docket Section (A-130), U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460, Attention: Docket No. A-79-08. The document "A Review of Standards of Performance for New Stationary Sources—Nitric Acid Plants" (EPA report number EPA-450/3-79-013) is available upon request from Mr. Robert Ajax (MD-13), Emission Standards and Engineering Division, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

FOR FURTHER INFORMATION CONTACT: Mr. Robert Ajax, (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Background

Prior to the promulgation of the NSPS in 1971, only 10 of the existing 194 weak nitric acid (50 to 60 percent acid) production facilities were specifically designed to accomplish NO_x abatement.

Without control equipment, total NO_x emissions are approximately 3,000 ppm in the stack gas, equivalent to a release of 21.5 kg/Mg (43 lb/ton) of 100 percent acid produced.

At the time of the NO_x New Source Performance Standard (NSPS) promulgation there were no State or locat NO_x emission abatement regulations in effect in the U.S. which applied specifically to nitric acid production plants. Ventura County, California, had enacted a limitation of 250 ppm NO_x to govern nitric acid plants as well as steam generators and other sources.

In August of 1971, the EPA proposed a regulation under Section 111 of the Clean Air Act to control nitrogen oxides emissions from nitric acid plants. The regulation, promulgated in December 1971, requires that no owner or operator of any nitric acid production unit (or "train") producing "weak nitric acid" shall discharge to the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2, in excess of 1.5 kg per metric ton of acid produced (3.0 lb per ton), the production being expressed as 100 percent nitric acid; and any gases which exhibit 10 percent opacity or greater.

The Clean Air Act Amendments of 1977 require that the Administrator of the EPA review and, if appropriate, revise established standards of performance for new stationary sources at least every 4 years [Section 111(b)(1)(B)]. This notice announces that EPA has completed a review of the standard of performance for nitric acid plants and invites comment on the results of this review.

Findings

Industry Growth Rate

The average rate of production increase for nitric acid fell from 9 percent/year in the 1960–1970 period to 0.7 percent from 1971 to 1977. The decline in demand for nitric acid parallels that for nitrogen-based fertilizers during the same period.

Nitric acid production shows an increasing trend toward plant/unit location and growth in the southern tier of States. In 1971, 48 percent of the national production was in the south. This figure increased to 54 percent in 1976.

About 50 percent of plant capacity in 1972 consisted of small to moderately sized units (50 to 300-ton/day capacity). Because of the economies of scale some producers are electing to replace their existing units with new, larger units. New nitric acid production units have been built as large as 910 Mg/day (1000 tons/day). The average size of new units is approximately 430 Mg/day (500 tons/day).

Control Technology

A mixture of nitrogen oxides (NO_x) is present in the tail gas from the ammonia oxidation process for the production of nitric acid. In modern U.S. single pressure process plants producing 50 to 60 percent acid, uncontrolled NO_x emissions are generated at the rate of about 21 kg/Mg of 100 percent acid (42 lb/ton) corresponding to approximately 3000 ppm NO_x (by volume) in the exit gas stream. The catalytic reduction process which was considered the best demonstrated control technology at the time the present standard was established has been largely supplanted by the extended absorption process as the preferred control technology for NO_x emissions from new nitric acid plants. The latter control system appears to have become the technology of choice for the nitric acid industry due to the increasing cost and danger of shortages of natural gas used in the catalytic reduction process. Since the energy crisis of the mid-1970's, over 50 percent of the nitric acid plants that had come on stream through mid-1978 and almost 90 percent of the plants scheduled to come on stream through 1979 use the extended absorption process for NO_x control.

Levels Achievable with Demonstrated Control Technology

All 14 of the new or modified operational nitric acid production units subject to NSPS and tested showed compliance with the current standard of 1.50 kg/Mg (3 lb/ton). The average of seven sets of test data from catalytic reduction-controlled plants is 0.22 kg/Mg (0.44 lb/ton), and the average of six sets of test data from extended absorption-controlled plants is 0.91 kg/Mg (1.82 lb/ton). All of the plants tested were in compliance with the opacity standard. It appears that the extended absorption process, while it has become the preferred control technology for NO_x control, cannot control these emissions as efficiently as the catalytic reduction process. In fact, over half of the test results for extended absorption were within 20 percent of the NO_x standard. The extended absorption process thus appears to have limitations with respect to NO_x control, and compares unfavorably with catalytic reduction in its ability to reduce NO_x emissions much below the present NSPS level.

Economic Considerations Affecting the NO_x NSPS

The annualized costs of the extended absorption process and the catalytic reduction NO_x control methods appear to be quite comparable. Capital cost for the extended absorption process is appreciably higher than that for catalytic reduction. However, this is offset by the higher operating cost of the latter system which requires increasingly costly natural gas.

Conclusions

Based on the above findings, EPA concludes that the existing standard of performance is appropriate at this time. While lower emission levels are attainable, the energy penalty and shortages of natural gas are concluded to be a basis for retaining the current standard of performance under Section 111 of the Clean Air Act. However, the recent deregulation will alter the price and availablity of natural gas, and provides a basis for optimism about its future availability for process and pollution control purposes. The Agency, therefore, plans to continue to assess the standard as the effect of deregulation materializes. Moreover, it should be noted that for the purpose of attaining and maintaining national ambient air quality standards and prevention of significant deterioration requirements, State Implementation Plan new source reviews may in come cases require greater emission reductions than those required by the standards of performance for new sources.

Public participation

All interested persons are invited to comment on this review, the conclusions, and EPA's planned action. Comments should be submitted to: Mr. Don Goodwin (MD–13), Emission Standards and Engineering Division, U.S. Environmenal Protection Agency, Research Triangle Park, North Carolina 27711.

Dated: June 11, 1979.

Douglas M. Costle,

Administrator.

[FR Doc. 79-19002 Filed 6-18-79; 8:45 am]

BILLING CODE 6560-01-M

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

SULFURIC ACID PLANTS

SUBPART H

NEW STATIONARY SOURCES: SULFURIC ACID PLANTS

Review of Performance Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Review of Standards.

SUMMARY: EPA has reviewed the standards of performance for sulfuric acid plants (40 CFR 60.80). The review is required under the Clean Air Act, as amended August 1977. The purpose of this notice is to announce EPA's decision to not revise the standards at this time and to solicit comments on this decision.

DATES: Comments must be received by May 14, 1979.

ADDRESS: Send comments to: Mr. Don Goodwin (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

FOR FURTHER INFORMATION CONTACT:

Mr. Robert Ajax, telephone: (919) 541-5271. The document "A Review of Standards of Performance for New Stationary Sources—Sulfuric Acid Plants" (EPA report number EPA-450/3-79-003) is available upon request from Mr. Robert Ajax (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

SUPPLEMENTARY INFORMATION:

BACKGROUND

Prior to the proposal of the standard of performance in 1971, almost all existing contact process sulfuric acid plants were of the single-absorption design and had no SO_2 emission controls. Emissions from these plants ranged from 1500 to 6000 ppm SO_2 by volume, or from 10.8 kg of SO_2/Mg of 100 percent acid produced (21.5 lb/ton) to 42.5 kg of SO_2/Mg of 100 percent acid produced (85 lb/ton). Several State and local agencies limited SO_2 emissions to 500 ppm from new sulfuric acid plants, but few such facilities had been put into operation (EPA, 1971).

In August of 1971, the Environmental Protection Agency (EPA) proposed a regulation under Section 111 of the Clean Air Act to control SO_2 and sulfuric acid mist emissions from sulfuric acid plants. The regulation, promulgated in December 1971, requires that no owner or operator of any new sulfuric acid production unit producing sulfuric acid by the contact process by burning elemental sulfur, alkylation acid, hydrogen sulfide, organic sulfides, mercaptans, or acid sludge shall discharge into the atmosphere any gases which contain sulfur dioxide in excess of 2 kg/Mg (4 lb/ton); any gases which contain acid mist, expressed as H_2SO_4, in excess of 0.075 kg/Mg of acid produced (0.15 lb/ton), expressed as 100 percent H_2SO_4; or any gases which exhibit 10 percent opacity or greater. Facilities which produce sulfuric acid as a means of controlling SO_2 emissions are not included under this regulation.

The Clean Air Act Amendments of 1977 require that the Administrator of the EPA review and, if appropriate, revise established standards of performance for new stationary sources at least every 4 years [Section 111(b)(1)(B)]. This notice announces that EPA has completed a review of the standard of performance for sulfuric acid plants and invites comment on the results of this review.

FINDINGS

INDUSTRY GROWTH

Since the proposal, 32 contact process sulfuric acid units have been constructed. Of these, at least 24 units result from growth in the phosphate fertilizer industry and are dedicated to the acidulation of phosphate rock, mainly in the Southern U.S.

In 1976, over 70 percent of the total national production of new sulfuric acid was in the South. It is projected that three of the four units predicted to be coming on line each year will most probably be located in the South.

BEST DEMONSTRATED CONTROL TECHNOLOGY

Sulfur dioxide and acid mist are present in the tail gas from the contact process sulfuric acid production unit. In modern four-stage converter contact process plants burning sulfur with approximately 8 percent SO_2 in the converter feed, and producing 98 percent acid, SO_2 and acid mist emissions are generated at the rate of 13 to 28 kg/Mg of 100 percent acid (26 to 56 lb/ton) and 0.2 to 2 kg/Mg of 100 percent acid (0.4 to 4 lb/ton), respectively. The dual absorption process is the best demonstrated control technology for SO_2 emissions from sulfuric acid plants, while the high efficiency acid mist eliminator is the best demonstrated control technology for acid mist emissions. These two emission control systems have become the systems of choice for sulfuric acid plants built or modified since the promulgation of the NSPS. Twenty-eight of the 32 sulfuric acid production plants subject to the standard incorporate the dual absorption process; all 32 plants use the high efficiency acid mist eliminator.

COMPLIANCE TEST RESULTS

All 32 sulfuric acid production units subject to the standard showed compliance with the current SO_2 standard of 2 kg/Mg (4 lb/ton). The 29 compliance test results for dual absorption plants ranged from a low of 0.16 kg/Mg (0.32 lb/ton) to a high of 1.9 kg/Mg (3.7 lb/ton) with an average of 0.9 kg/Mg (1.8 lb/ton). Information received on the performance of several sulfuric acid plants indicates that low SO_2 emission results achieved in NSPS compliance tests apparently do not reflect day-to-day SO_2 emission levels. These levels appear to rise toward the standard as the conversion catalyst ages and its activity drops. Additionally, there may be some question about the validity of low SO_2 NSPS values, i.e., less than 1 kg/Mg (2 lb/ton), due to errors in the application of the original EPA Method 8. This method was revised on August 18, 1977, to include more detailed procedures to prevent such errors.

All 32 affected sulfuric acid production units also showed compliance with the current acid mist standard of 0.075 kg/Mg of 100 percent acid (0.15 lb/ton). The compliance test data are all from plants with acid mist emission control provided by the high efficien-

cy acid mist eliminator. The data showed a range with a low of 0.008 kg/Mg (0.016 lb/ton) to a high of 0.071 kg/Mg (0.141 lb/ton), and an overall average value of 0.04 kg/Mg (0.081 lb/ton). Acid mist emission (and related opacity) levels are unaffected by factors affecting SO_2 emissions, i.e., conversion efficiency and catalyst aging. Rather, acid mist emissions are primarily a function of moisture levels in the sulfur feedstock and air fed to the sulfur burner, and the efficiency of the final absorber operation. The order-of-magnitude spread observed in compliance test values is probably a result of variation in these factors. Additionally, the potential for imprecision in the application of the original EPA Method 8 may have contributed to this spread.

POSSIBLE REVISION TO STANDARD

The compliance test data indicate that the available control technology could possibly meet both lower sulfur dioxide and sulfuric acid mist emission standards. However, the available test data indicate that variability in indicated emission rates occurs—possibly as a result of process variables, and test method precision. Therefore, to meet a tighter standard designers and operators would need to design for attainment of a lower average emission rate in order to retain a margin of safety needed to accommodate emission variability. The available compliance data do not provide a basis for concluding that this is possible.

In contrast, the effect of catalyst aging is controllable by more frequent replacement. As an outside limit, complete replacement of catalyst in the first 3 beds of a four-bed converter 3 times as frequently as is normally practiced could potentially maintain emissions in the range of 1 to 1.5 kg/Mg and would result in a net emission reduction of approximately 0.3 kg/Mg (0.6 lb/ton).

Based on an estimated sulfuric acid plant growth rate of four new production lines per year between 1981 and 1984, a 50 percent reduction of the present SO_2 NSPS level—from 2 kg/Mg (4 lb/ton) to 1 kg/Mg (2 lb/ton)—would result in a drop in the estimated SO_2 contribution to these new sulfuric acid plants to the total national SO_2 emissions, from 0.04 percent to 0.02 percent (8,000 tons to 4,000 tons).

CONCLUSIONS

Based upon the above findings, EPA concludes that the current best demonstrated control technology, the duel absorption process and the acid mist eliminator are identical in basic design to that used as the rationale for the original SO_2 standard. Therefore, from the standpoint of control technology, and considering costs, and the small quantity of emissions in question, it does not appear necessary or appropriate to revise the present standard of performance adopted under Section 111 of the Clean Air Act. It should be noted that for the purpose of attaining national ambient air quality standards and prevention of significant deterioration, State Implementation Plan new source reviews may in some cases require greater emission reductions than those required by standards of performance for new sources.

PUBLIC PARTICIPATION

All interested persons are invited to comment on this review, the conclusions, and EPA's planned action. Comments should be submitted to: Mr. Don Goodwin (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711.

(Section 111(6)(1)(B) of the Clean Air Act, as amended (42 U.S.C. 7411(6)(1)(B)).

Dated: March 9, 1979.

DOUGLAS M. COSTLE,
Administrator.

[FR Doc. 79-7926 Filed 3-14-79; 8:45 am]

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

PETROLEUM REFINERY

SUBPART J

40 CFR Part 60

[FRL 1295-1]

Standards of Performance for New Stationary Sources: Petroleum Refineries Review of Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Review of Standards.

SUMMARY: EPA has reviewed its standard of performance for petroleum refineries (40 CFR 60.100, Subpart J). The review is required under the Clean Air Act, as amended August 1977. The purpose of this notice is to announce EPA's intent to undertake the development of a revised standard which would limit SO_2 emissions from catalyst regenerators.

DATE: Comments must be received by December 21, 1979.

ADDRESS: Send comments to: Central Docket Section (A-130), U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460, Attention: Docket A-79-09.

The document "A Review of Standards of Performance for New Stationary Sources—Petroleum Refineries" (EPA-450/3-79-008) is available upon request from Mr. Robert Ajax (MD-13), Emission Standards and Engineering Division, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

FOR FURTHER INFORMATION CONTACT: Mr. Robert Ajax, Telephone: (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Background

New Source Performance Standards (NSPS) for petroleum refineries were promulgated by the Environmental Protection Agency on March 8, 1974. (40 CFR 60.100, Subpart J). These standards regulate the emission of particulate matter and carbon monoxide, and the opacity of flue gases from fluid catalytic cracking unit (FCCU) catalyst regenerators and FCCU regenerator incinerator-waste heat boilers. They also regulate the emission of sulfur dioxide from fuel gas combustion devices. These regulations apply to any affected facility which commenced construction or modification after June 11, 1973.

The Clean Air Act Amendments of 1977 require that the Administrator of the EPA review and, if appropriate, revise established standards of performance for new stationary sources at least every 4 years [Section 111(b)(1)(B)]. This notice announces that EPA has completed a review of the standard of performance for petroleum refineries and invites comment on the results of this review.

Findings

On the basis of a review of compliance data available in EPA's Regional Offices and a review of literature describing recent control technology applicable to catalyst regenerators and fuel gas combustion devices, EPA has made the following conclusions regarding the need to revise the existing standard.

Particulate Matter

The available data indicate that the current limitation on particulate matter emissions accurately reflects the performance capability of best available control systems. It is, therefore, concluded that no revision should be made to the particulate standard. New technologies such as high efficiency separators, high temperature regenerators, and new catalysts have reduced the total quantity of uncontrolled particulate matter emitted. However, the method established in the standard for calculating the allowable emissions effectively corrects for the reduction due to changes in catalysts and operating procedures.

While it is concluded that the particulate matter standard should not be revised, a question has been raised as to the validity of Reference Method 5 when high concentrations of condensible sulfur compounds are present. This test method, which is used to measure compliance with the particulate standard, operates at a nominal temperature of 120°C and, as such, is capable of collecting condensible matter which exists in gaseous form at stack temperature. If significant quantities of such condensible material exist which are not controllable by the best systems of emission reduction, then a facility employing such systems could be found to be in non-compliance with the standard. An analysis of data available when the standard was established indicated this was not a problem at that time. However, with high sulfur content feed, there is evidence that condensible sulfur oxides may exist at concentrations sufficient to affect compliance.

EPA is currently studying this question. Depending on the results of this study, EPA may revise the standard or the test method.

Carbon Monoxide

The present standard for carbon monoxide emissions was established at a level which would permit regenerator in situ combustion. This method of controlling carbon monoxide emissions offers production and energy efficiencies but is recognized to be less effective than a carbon monoxide boiler. No new data were obtained during this review to alter the original finding that it is not practical to control CO emissions to less than 500 ppm by in situ regeneration and, therefore, no revision in the standard is planned at this time. However, it should be noted that the recent advent and increased use of CO oxidation catalysts and additives may provide data showing that concentrations lower than 500 ppm are achievable. If such data become available, the Agency will consider revision of the standard. It should be further noted that for the purpose of attaining and maintaining the national ambient air quality standards, State Implementation Plan new source reviews may, in some cases, require greater CO emission reductions than those required by the standards of performance for new sources.

At the time the standard was established, EPA concluded that CO emissions should be continuously monitored. A requirement for such monitoring was, therefore, included in the standard. This requirement is applicable to all catalyst regenerators subject to the standard. However, the effective date of the monitoring requirement was deferred until EPA develops performance specifications for CO monitoring systems. EPA has found no basis for revising this monitoring requirement and performance specifications are currently under development and evaluation. It is planned to issue an advanced notice of proposed rulemaking in 1979 setting forth the specifications which have been developed and which will be assessed in field studies.

Sulfur Dioxide

The present standard currently limits SO_2 emissions resulting from the combustion of fuel gas. The catalyst regenerator is also a significant source of SO_2 emissions but is not subject to the standard. The review considered both the need to revise the current limitation and the need to include limitations on SO_2 emissions from the catalyst regenerator..

Available compliance test data indicate that the current standard limiting sulfur to 230 mg H_2S/dscm from combustion of fuel gas is being met and, in some cases, exceeded by a wide margin. Six tests showed an average of 107 mg H_2S/dscm and a range of 7 to 229 mg H_2S/dscm. While these data indicate that a reduction in the present limitation

is possible, the range exhibited is consistent with the control device performance documented at the time the standard was established. On the basis of this, along with the increased sulfur content of feedstock expected with increased imports and the variable crude oil supply conditions now existing, it is concluded that the fuel gas sulfur limitation is appropriate and that no revision is needed.

A deficiency in the current standard limiting sulfur in fuel gas relates to the lack of a continuous monitoring method. EPA recognized the need for continuous monitoring at the time the standard was adopted. However, at that time, no monitoring systems had been demonstrated to be adequate for this purpose and EPA had not established performance specifications for such systems. Consequently, application of the monitoring requirement was deferred until performance specifications could be adopted. Since the adoption of the standard, EPA has pursued a program to develop and assess the performance of an H_2S monitoring system. On this basis, performance specifications are now being developed. It is planned to issue an advanced notice of proposed rulemaking in 1979 setting forth the specifications which have been developed and which will be assessed in field studies.

During the review of the standard, an ambiguity was identifed in the current limitation on sulfur in fuel gas concerning the applicability of this limitation to fuel gas burned in waste-heat boilers. To clarify this, an amendment was prepared which was published in the **Federal Register** on March 12, 1979. This amendment makes clear that fuel gas fired in waste-heat boilers is not exempt from the standard.

Sulfur dioxide emissions from fluid catalytic cracking unit (FCCU) catalyst regenerators are not regulated by the standard. However, sulfur dioxide scrubber technology is available and being used to control steam generator emissions and a limited number of FCCU regenerators. Also, Amoco Oil Company has developed a new cracking process which reduces sulfur oxide emissions from FCCU regenerators. The process uses a new catalyst that retains sulfur oxides and returns them to the reactor where they are removed with the product stream. If a low sulfur product is required, the sulfur will be removed by amine stripping or hydrotreating and eventually recovered in a sulfur recovery unit. Pilot tests indicate that the new catalyst is capable of reducing sulfur oxide emissions 80 to 90 percent and commercial tests are planned to confirm these data.

The potential uncontrolled emissions from new, modified, or reconstructed catalyst regenerators are significant. Uncontrolled emission rates from catalyst regenerators are typically 5 to 10 Mg/day and range up to 100 Mg/day from the largest units. The growth rate in terms of new catalyst regenerators is uncertain due to the present uncertainty of petroleum supplies and demand. However, for perspective a growth rate of 0.5 percent in capacity from 1979 through 1985 would result in additional emissions from uncontrolled new sources of 23 Mg per day in 1986; a growth rate of 0.75 percent would result in additional uncontrolled emissions of 58 Mg SO_x/day. Emissions from modified or reconstructed sources would add to this total.

Based on the existence of these SO_2 control technologies, EPA plans to initiate a program later this year to assess the applicability, cost, performance, and non-air environmental impacts of these technologies. If supported by the findings of this program EPA will propose a limit on FCCU SO_2 emissions.

Volatile Organic Compounds

The emission of volatile organic compounds (VOC) from FCC unit regenerators is not limited in the present NSPS. These are, however, of concern, both because of their role as oxidant precursors and as potentially hazardous compounds. Of particular concern are the polynuclear aromatic compounds (PNA) because of their potential carcinogenic effects. The most abundant PNA measured in regenerator flue gas is benzo-a-pyrene (BAP) with a concentration of 0.218 kg BAP/1,000 barrels of feed. The concentration of BAP can effectively be reduced in a carbon monoxide boiler to 1.41×10^{-5} kg BAP/1,000 barrels of feed. However, there are no data indicating the concentration of BAP in the flue gas from high temperature (in situ) regeneration nor from regenerators using CO oxidation promoting catalyst. This, therefore, has been identified as an area for future study by EPA's Office of Research and Development.

Public Participation

All interested persons are invited to comment on this review, the conclusions, and EPA's planned action.

Douglas M. Costle,

Administrator.

Dated: October 15, 1979.

[FR Doc. 79-32567 Filed 10-19-79, 8:45 am]

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1423-2]

Standards of Performance for New Stationary Sources; Petroleum Refineries; Clarifying Amendment

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed Rule.

SUMMARY: This proposed action clarifies which gaseous fuels used at petroleum refineries are covered by the existing standards of performance for petroleum refineries (40 CFR 60.100). This action will not change the environmental, energy, and economic impacts of the existing standards.

DATE: Comments must be received on or before May 2, 1980.

ADDRESSES: *Comments.* Comments should be submitted (in duplicate if possible) to: Central Docket Section (A-130), Attention: Docket Number A-79-56, U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460. *Docket.* The Docket, Number A-79-56, is available for public inspection and copying at EPA's Central Docket Section, Room 2902 Waterside Mall, Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Susan R. Wyatt, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5477.

SUPPLEMENTARY INFORMATION: On March 12, 1979, EPA published in the **Federal Register** (44 FR 13480) a clarifying amendment intended to "reduce confusion concerning the applicability of the sulfur dioxide standard to incinerator-waste heat boilers installed on fluid or Thermofor catalytic cracking unit catalyst regenerators and fluid coking unit coke burners." That action included a change in the definition of "fuel gas." It now appears the revised definition of "fuel gas" could easily be interpreted to include natural gas as a fuel gas. This would mean that refineries using natural gas would be subject to the expense of performance testing, monitoring, and reporting requirements even though the natural gas contained essentially no sulfur and did not result in emissions of sulfur dioxide when combusted.

The intent of the existing standards of performance for refinery fuel gas has always been to prevent emissions of sulfur dioxide resulting from the burning of gaseous fuels containing hydrogen sulfide. Generally, natural gas used in refineries is purchased from outside sources and delivered to the refinery via pipelines. This natural gas contains only trace amounts of hydrogen sulfide due to specifications established to protect the pipelines from corrosion. It would impose an unnecessary burden on refineries to require performance testing, monitoring, and reporting where this natural gas is burned by itself.

In a few cases, however, a refinery may generate natural gas. There may be no legal or technical requirement that this gas be desulfurized before combustion. If this gas contains appreciable hydrogen sulfide and other sulfur constituents, significant emissions of sulfur dioxide would result when it is burned. The existing standards of performance for petroleum refineries were intended to cover these types of gases. Consequently, the definition of "fuel gas" is rewritten to clarify that only natural gas generated at a petroleum refinery is to be considered fuel gas. The effective date of the revised definition would be March 12, 1979.

Miscellaneous: Under Executive Order 12044, EPA is required to judge whether a regulation is "significant" and therefore subject to the procedural requirements of the Order or whether it may follow other specialized development procedures. EPA labels these other regulations "specialized." I have reviewed this regulation and determined that it is a specialized regulation not subject to the procedural requirements of Executive Order 12044.

Dated: February 26, 1980.

Douglas M. Costle,

Administrator.

It is proposed to amend Part 60 of Chapter I, Title 40 of the Code of Federal Regulations by revising paragraph (d) as follows:

60.101 Definitions.

* * * * *

(d) "Fuel gas" means natural gas generated at a petroleum refinery, or any gas generated by a refinery process unit, which is combusted separately or in any combination with any type of natural gas. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners.

* * * * *

(Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a))

[FR Doc. 80-6596 Filed 2-29-80; 8:45 am]

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

SECONDARY BRASS OR BRONZE INGOT PRODUCTION PLANTS

SUBPART M

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 60]

[FRL-1231-1]

Review of Standards of Performance for New Stationary Sources: Secondary Brass and Bronze Ingot Production

AGENCY: Environmental Protection Agency (EPA).

ACTION: Review of Standards.

SUMMARY: EPA has reviewed the standard of performance for secondary brass and bronze ingot production plants (40 CFR 60. 130, Subpart M). The review is required under the Clean Air Act, as amended August 1977. The purpose of this notice is to announce EPA's intent not to undertake revision of the standards at this time.

DATES: Comments must be received on or before August 20, 1979.

ADDRESSES: Comments should be sent to the Central Docket Section (A-130). U.S. Environmental Protection Agency, 401 M Street, SW., Washington, D.C. 20460, Attention: Docket No. A-79-10. The Document "A Review of Standards of Performance for New Stationary Sources—Secondary Brass and Bronze Plat Plants" (EPA-450/3-79-011) is available upon request from Mr. Robert Ajax (MD-13), Emission Standards and Engineering Division, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

FOR FURTHER INFORMATION CONTACT: Mr. Robert Ajax, telephone: (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Background

In June of 1973, the EPA proposed a standard under Section 111 of the Clean Air Act to control particulate matter emissions from secondary brass and bronze ingot production plants (40 CFR 60.230, Subpart M). The standard, promulgated in March 1974, limits the discharge of any gases into the atmosphere from a reverberatory furnace which;

1. Contain particulate matter in excess of 50 mg/dscm (0.022 gr/dscf).

2. Exhibit 20 percent opacity or greater.

In addition, any blast (cupola) or electric furnace may not emit any gases which exhibit 10 percent opacity or greater.

The Clean Air Act Amendments of 1977 require that the Administrator of the EPA review and, if appropriate, revise established standards of performance for new stationary sources at least every 4 years [Section 111(b)(1)(B)]. This notice announces that EPA has completed a review of the standard of performance for secondary brass and bronze ingot production plants and invites comment on the results of this review.

Findings

Industry Statistics

In 1969, there were approximately 60 brass and bronze ingot production facilities in the United States. Currently, only 35 facilities are operational, and only one facility has become operational since the promulgation of the NSPS in 1974. No new facilities or modifications are know to be currently planned or under construction.

Ingot production has shown a steady decline from the 1966 peak year production of 315,000 Mg (347,000 tons) to a low of 160,000 Mg (186,000 tons) in 1975, the last year for which nationwide statistics were published. The decline has been caused by a decline in the demand for products made with brass or bronze and large scale substitution of other materials or technologies for the previously used brass or bronze. No information has been reported which would indicate a reversal of the decline in brass and bronze ingot production or in the number of operating plants.

Emissions and Control Technology

The current best demonstrated control technology, the fabric filter, is the same as when the standards were originally promulgated. No major improvements in this technology have occurred during the intervening period.

High-pressure drop venturi scrubbers are used, to some extent, in the brass and bronze industry, but their overall control efficiency is lower than that of fabric filters. Electrostatic precipitators have not been used in the industry due to both the low gas flow rates and high resistivity of metallic fumes.

Only one facility has become subject to the standard since its original promulgation. This facility was tested in February 1978. The average test result of 16.9 milligrams/dry standard cubic meters (mg/dscm), or 0.0074 grains/dry standard cubic feet (gr/dscf), is lower than most of the test data used for justification of the current standard of 50 mg/dscm (0.022 gr/dscf), but this single test is not considered sufficient to draw any overall conclusion about improved control technology.

Fugitive emissions continue to be a problem in the brass and bronze industry. In most cases, these emissions are very difficult to capture and equally difficult to measure during testing. It was primarily for the former reason that the current particulate standard does not apply during pouring of the ingots. This overall situation has not changed in that only complete enclosure of the furnace can result in full control of fugitive emissions. However, information is available indicating that there may be additives capable of reducing fugitive emissions during pouring. Also, improved control of fugitive emissions may be possible through improved hood design.

Conclusions

Based on the above findings, EPA concludes that the existing standard of performance is appropriate and no revision is needed. While extension of the standard to include fugitive emissions would be possible, the lack of anticipated growth in the industry does not justify such action.

PUBLIC PARTICIPATION: All interested persons are invited to comment on this review and the conclusions.

Dated: June 12, 1979.

Douglas M. Costle,

Administrator.

[FR Doc. 79-19003 Filed 6-18-79, 8:45 am]

BILLING CODE 6560-01-M

ENVIRONMENTAL PROTECTION AGENCY

■

BASIC OXYGEN PROCESS FURNACES

Standards of Performance For New Stationary Sources

SUBPART N

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 60]

[FRL 1012-1]

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES: IRON AND STEEL PLANTS, BASIC OXYGEN FURNACES

Review of Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION. Review of standards.

SUMMARY: EPA has reviewed the standards of performance for basic oxygen process furnaces (BOPFs) used at iron and steel plants. The review is required under the Clean Air Act, as amended in August 1977. The purpose of this notice is to announce EPA's intent to propose amendments to the standards at a later date.

DATES: Comments must be received by May 21, 1979.

ADDRESS: Send comments to: Mr. Don Goodwin (MD-13), Emission Standards and Engineering Division, U.S. Environmental Protection Agency, Research Triangle Park, N.C. 27711.

FOR FURTHER INFORMATION CONTACT:

Mr. Robert Ajax, telephone: (919) 541-5271.

The document "A Review of Standards of Performance of New Stationary Sources—Iron and Steel Plants/ Bassic Oxygen Furnaces" (report number EPA-450/3-78-116) is available upon request from Mr. Robert Ajax (MD-13), Emission Standards and Engineering Division, U.S. Environmental Protection Agency, Research Triangle Park, N.C. 27711.

SUPPLEMENTARY INFORMATION:

Background

Particulate matter emissions from BOPFs fall in two categories, primary and secondary. Emissions associated with the oxygen blow portion of the BOPF are termed "primary" emissions. These emissions are generated at the rate of 25 to 28 kg/Mg (50 to 55 lb/ton) of raw steel. Emissions generated during ancillary operations, such as charging and tapping, are termed "secondary" or fugitive emissions. These emissions are generated at a lower rate in the range of 0.5 to 1 kg/ Mg (1 to 2 lb/ton) of raw steel.

In June of 1973, EPA proposed a regulation under Section 111 of the Clean Air Act to control primary particulate emissions from basic oxygen process furnaces at iron and steel plants. The regulation, promulgated in March 1974, requires that no owner or operator of any furnace producing steel by charging scrap steel, hot metal, and flux materials into a vessel and introducing a high volume of an oxygen-rich gas shall discharge into the atmosphere any gases which contain particulate matter in excess of 50 mg/ dscm (0.022 gr/dscf).

The Clean Air Act Amendments of 1977 require that the Administrator of the EPA review and, if appropriate, revise established standards of performance for new stationary sources at least every 4 years (Section 111(b)(1)(B)). This notice announces that EPA has completed a review of the standard of performance for basic oxygen process furnaces at iron and steel plants and invites comment on the results of this review.

Findings

INDUSTRY GROWTH RATE

The present economic conditions in the United States and worldwide steel industry have created a significant excess U.S. BOPF capacity and a tightening of the availablitly of capital for future expansion. Since the promulgation of the BOPF standard, new BOPF construction has declined significantly. For example, three of the four units scheduled for startup in 1978 were originally scheduled to begin production in 1974. This coupled with the lack of any additional industry announcements of new U.S. BOPF contruction, indicates that construction of new BOPFs which would be subject to a revised new source performance standard (NSPS) is not likely to commence before 1980, if then. Construction of new plants beyond 1980 will be dictated by domestic economic conditions and international competition, and is, therefore, uncertain.

PRIMARY EMISSION CONTROL

Review of the literature and performance test data indicates that the use of a closed hood in conjunction with a scrubber or an open hood in conjunction with either a scrubber or electrostatic precipitator currently represents the best demonstrated control technologies for controlling BOPF primary emissions. All BOPFs that have been installed since 1973 incorporate closed hood systems for particulate emission control. The closed hood control system in combination with a venturi scrubber has become the system of choice of the U.S. steel industry because this system saves energy and has generally lower maintenance requirements compared with the older open-hood electrostatic precipitator system. Use of the closed hood system requires that approximately 80 percent less air be cleaned than with the open hood system. The potential also exists with the closed hood system for using the carbon monoxide off-gas as a fuel source.

As of early 1978, no NSPS compliance tests had been carried out since the promulgation of the standard. Pertinent data are available, however, from emission tests on a limited number of new BOPFs. These tests, carried out using EPA Method 5, indicate that primary particulate emission levels of between 32 and 50 mg/dscf (0.014 and 0.022 gr/dscf) are being achieved using the same control technology as that existing at the time the standard for primary emissions was established for BOPFs. The rationale for the current NSPS level of 50 mg/ dscm (0.022 gr/dscf) for primary stack emissions, as described in 1973, is therefore, still considered to be valid.

SECONDARY EMISSION CONTROL TECHNOLOGY

Secondary or fugitive emissions not captured by the BOPF primary emissions control system during various BOPF ancillary operations currently amount to more than 100 tons annually. One of the principal sources of these emissions, the hot metal charging cycle, can generate amounts of fugitive emissions on the order of 0.25 kg/Mg (0.5 lb/ton) of charge. These emissions are presently uncontrolled in most of the older BOPFs and only partially controlled in most BOPFs that have come on stream during the past 5 years.

Control of secondary emissions involves a developing technology that requires in-depth study to determine the most effective methods of fume capture. Although potentially expensive to construct, the complete furnace enclusure equipped with several auxiliary hoods is currently the only demonstrated technology exhibiting the potential for effectively minimizing fugitive emissions from a new BOPF.

Seven new BOPFs installed in the U.S. in the past 7 years have incorporated partial or full furnace enclosures as part of the original particulate emission control system. Since these designs had deficiencies, these systems are operating with varying degrees of success. Six new furnace enclosure installations due to commence operations in 1978, including four on new BOPFs and two retrofit installations, will incorporate a secondary hood inside the furnace enclosure with sufficient volume for fugitive emission control.

CLARIFICATION OF WORDING OF NSPS STANDARD

Review of the existing standard revealed possible ambiguity in the wording of the NSPS with regard to the

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

SEWAGE TREATMENT PLANTS

SUBPART O

40 CFR Part 60

[FRL 1310-3]

Standards of Performance for New Stationary Sources: Sewage Treatment Plants; Review of Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION Review of standards.

SUMMARY: EPA has reviewed the standards of performance for sewage treatment plant sludge incinerators (40 CFR 60.150). The review is required under the Clean Air Act, as amended August 1977. The purpose of this notice is to announce EPA's plan to defer decision on the need to revise the standards and to undertake a program to further assess emission rates, control technology, and the current standard.

DATES: Comments must be received by January 28, 1980.

ADDRESS: Comments should be submitted to the Central Docket Section (A-130), U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460, Attention: Docket No. A-79-17.

FOR FURTHER INFORMATION CONTACT: Mr. Robert Ajax, telephone: (919) 541-5271 The document "A Review of Standards of Performance for New Stationary Sources—Sewage Sludge Incinerators" (EPA-450/3-79-010) is available upon request from Mr. Robert Ajax (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

SUPPLEMENTARY INFORMATION:

Background

Prior to the promulgation of the NSPS in 1974, most sewage sludge incinerators utilized low pressure scrubbers (2 to 8 in WG) to reduce emissions to the atmosphere. These scrubbers were designed to meet State and local standards that were on the order of 0.2 to 0.9 grams/dry standard cubic meter (dscm) or 0.1 to 0.4 grains/dry standard cubic foot (dscf) at 50 percent excess air Incineration standards, for the most part, reflected general incineration of all types with emphasis on municipal solid waste. A separate standard for sewage sludge incineration emissions was unusual. Control efficiencies, based on an uncontrolled rate of 0.9 grains/dscf, were between 50 and 90 percent.

In June of 1973, the Environmental Protection Agency proposed a standard under Section 111 of the Clean Air Act to control particulate matter emissions from sewage sludge incinerators. The standard, promulgated in March 1974 and amended in November 1977, applies to any incinerator constructed or modified after June 11, 1973, that burns wastes containing more than 10 percent sewage sludge (dry basis) produced by municipal sewage treatment plants, or charges more than 1000 kg (2205 lb/day) municipal sewage sludge (dry basis). The standard prohibits the discharge of particulate matter at a rate greater than 0.65 grams/kg of dry sludge input (1.30 lb/ton) and prohibits the discharge of any gases exhibiting 20 percent opacity or greater.

The Clean Air Act Amendments of 1977 require that the Administrator of the EPA review and, if appropriate, revise established standards of performance for new stationary sources at least every 4 years [Section 111(b)(1)(B)]. This notice announces that EPA has undertaken a review of the standard of performance for sewage sludge incinerators and sets forth initial findings based on this review. EPA is however, deferring a final decision on the need to revise the standard until further data can be obtained and analyzed pertaining to the form of the standard, parameters affecting emission rates, and coincineration. Comments on these findings and this action are invited.

Findings

Status of Sewage Sludge Incinerators

It is estimated that approximately 240 municipal sludge incinerator units are presently in operation. A large number of incinerators were built in the 1967-1972 period and this growth has continued, although at a somewhat slower rate since 1972. A compilation of incinerator units subject to the construction grants program indicated that 92 new units were either in the contruction or planning stages in mid-1977. A total of 23 sludge incinerators have been identified which are subject to the standard and which have been tested for compliance.

Emission Rates and Control Technology

Particulate matter from the inert material in sludge is present in the flue gas of sewage sludge incinerators. Uncontrolled emissions may vary from as low as 4 g/kg (8 lb/ton) dry sludge input to as high as 110 g/kg (220 lb/ton) dry sludge input depending upon the incinerator type and the sludge composition (e.g., percent volatile solids, percent moisture, and source treatment). Since adoption of the standard, wet scrubbers operating with pressure drops in the range of 7 to 32 in. WG and a mean of 20 in. WG have been employed exclusively and have been successful for controlling emissions to the level required by the standard. The average emission from tests of 26 facilities since 1974 was 0.55 g/kg with a standard deviatin of 0.35 g/kg (1.1 ±0.7 lb/ton) dry sludge input. When tests from one obviously underdesigned facility and three facilities not subject to the standard were deleted, the average emission was 0.45 g/kg with a standard deviation of 0.17 g/kg (0.91 ± 0.33 lb/ton) dry sludge input or about 30 percent below the standard. The scrubber configurations which were employed included three-stage perforated plate impingment scrubbers operating at 7 to 9 in WG and venturi scrubbers, or venturi scrubbers in series with various impingment plate scrubbers operating in the 9 to 32 in. WG range.

While these test results are consistent with the standard, an analysis of the test results shows an inconsistent relationship between scrubber pressure drop and emissions as expressed in units of the standard. This appears to be due to both the facility type and input sludge composition, particularly solids content. Moreover, experimental data from some of the tested units suggest that incinerators burning sludge below 20 percent solids may have difficulty complying with the NSPS. Because combustion air requirements per unit of dry sludge increase with increasing sludge moisture, actual stack volume concentrations of 0.01 grains/dry standard cubic meter or less are needed to meet the standard when high moisture sludges are incinerated. For example, two incinerators burning sludges of 16 percent solids achieved only marginal compliance and low volume concentrations of 0 009 and 0.010 grains/acf.

An additional finding based on an analysis of the test data which are now available concerns the relationship between emissions expressed in terms of grain loading on a dry basis and emissions per weight of dry sludge burned. As initially proposed, the standard was expressed as a volume concentration standard equal to 0.031 grains/dscf. Due to comments received relative to the use of dilution air and the difficulties involved in measuring and correcting to dry volume, the promulgated standard was established at 1.3 lb/dry ton sludge input. This was based on data available at the time of promulgation showing that the promulgated and proposed standards were equivalent. However, an analysis

of the data which are now available indicate a nominal equivalence between 1.8 lb/ton dry sludge and 0.031 grains/dscf for typical sludges.

One factor at least partially responsible for the difference in equivalent emission factors, in addition to affecting the relationship between pressure drop and mass emissions, is the moisture content in the input sludge. The average solids content of the sludge associated with the data cited above is 24 percent. However, tests of two other facilities with input sludge having a relatively high solids content of between 27 and 33 percent showed an equivalence similar to that found by EPA in 1973 (e.g., 0.03 grains/dscf equivalent to 1.3 lb/ton dry sludge input).

Opacity levels from successful emissions tests never exceeded 15 percent and were most often either 0 or 5 percent. These results are similar to those found when the standard was first proposed as a 10 percent value with exceptions allowed during 2 minutes of a 60 minute test cycle. This standard was changed to 20 percent with no exemptions except during startup, shut down, or malfunctions. The current data indicate that the rationale used to arrive at the 20 percent opacity level till applies. This rationale, in addition to field observations obtained with Method 9, involved instrumental data and theoretical projections of the opacity which could, under extreme conditions, occur at a facility complying with the particulate matter standard. A reevaluation of this standard was undertaken and reaffirmation was announced in the **Federal Register** on February 18, 1976.

Application of the Standard to Coincineration

The coincineration of municipal solid waste and sewage sludge has been practiced in Europe for several years, and on a limited scale in the U.S. However, as energy resources become scarce and more costly, and where land disposal is economically or technically unfeasible, the recovery of the heat content of dewatered sludge as an energy source will become more desirable. Due to this and the institutional commonality of these wastes and advances in the preincineration processing of municipal refuse to a waste fuel, many communities may find joint incineration in energy recovery incinerators an economically attractive alternative to their waste disposal problems.

Coincineration of municipal solid waste and sewage sludge, as described above, is not explicitly covered in 40 CFR 60. The particulate standard for municipal solid waste described in Subpart E (0.18 g/dscm or 0.08 g/dscf at 12 percent CO_2) applies to the incineration of municipal solid waste in furnaces with a capacity of at least 45 Mg/day (50 tons/day). Subpart O, the particulate standard for sewage sludge incineration (0.65 g/kg dry sludge input or 1.3 lb/ton dry sludge), applies to any incinerator that burns sewage sludge, with the exception of small communities practicing coincineration.

To clarify the situation when coincineration is involved, EPA adopted the policy that when an incinerator with a capacity of at least 45 Mg/day (50 tons/day) burns at least 50 percent municipal solid waste, then the Subpart E applies regardless of the amount of sewage sludge burned. When more than 50 percent sewage sludge and more than 45 Mg/day (50 tons) is incinerated, the standard is based upon Subpart O or, alternatively, a proration between Subparts O and E. The proration scheme, however, has a discontinuity when a municipal incinerator burns 50 percent solid waste.

The alternative of prorating the Subparts E and O is not straightforward, since the two standards are stated in different units. The proration scheme requires a transformation of the municipal incineration standard (Subpart E) from grams per dry standard cubic meter (grains per dry standard cubic foot) at 12 percent CO_2 to grams per kilograms (pounds per dry ton) refuse input, or a transformation of the sewage sludge standard (Subpart O) from grams per dry kilograms (pounds per dry ton) input to grams per dry standard cubic meter at 12 percent CO_2. Such transformations are dependent on the percent CO_2 in the flue gas stream, the stoichiometric air requirements, excess air, the volume of combustion products to require air, and percent moisture in refuse or sludge, and the heat content of the sludge and solid waste.

Other Pollutants

Incineration of sewage sludge results in the emission to the atmosphere of trace elements and compounds, some of which are hazardous or potentially hazardous. Substances of concern include mercury, lead, cadmium, pesticides, and organic matter. Among these, mercury emissions from sewage sludge incinerators are specifically limited under the National Emission Standards for Hazardous Air Pollutants (40 CFR 61.50 et seq.).

The emission of other trace compounds and elements, while not subject to specific limitations is controlled by particulate matter control equipment or directly by the high temperatures in the combustion process and with the exception of cadmium, no data were obtained during this review to indicate a need for specific limitations on emissions of these materials resulting from incineration of typical sludges. Tests have shown high destruction efficiencies for pesticides, and organics in sewage sludge incinerators. Similarly, test data suggest that high pressure scrubbers of the type normally employed to meet the particulate standards also reduce lead emissions to below the level required to meet ambient standards. In contrast, data suggest that cadmium emissions may not be adequately controlled. A separate program is underway in EPA to independently assess the need to regulate cadmium. Final decisions on this will be announced in a separate action. In the event that the need to limit cadmium emissions from sewage sludge incinerators is indicated, appropriate action will be taken.

Conclusions

The available test data support the validity of the standard. However, the marginal compliance of several facilities operating with high pressure drops, the apparent relationship between sludge moisture content and emission rates, and the inconsistent relationship between pressure drop and scrubber performance as measured in terms of the standard are matters which require further study. Such a study will be undertaken later and will include further analysis of data regarding sludge dewatering, incinerator types, control technology, and the relationship between control device operating parameters, sludge solids content, emission rates, and alternative forms for expression of emission rates. This will also include an analysis of alternative means for establishment of standards applicable to coincineration. A final conclusion on the need for revision of the standard will not be made until this study is complete.

Dated: November 16, 1979.

Barbara Blum,

Acting Administrator.

[FR Doc 79-36473 Filed 11-26-79, 8:45 am]

definitions of a BOPF. Also, the definition of the operating cycle during which sampling is performed requires clarification. Specifically, the stack emissions averaged over the oxygen blow part of the cycle could be significantly different from the emissions averaged over a period or periods that includes scrap preheating and turndown for vessel sampling. The current standard is unclear as to which averaging time should be used. Since no tests to date have come under the NSPS, averaging time has not been an issue; however, interpreting the standard will be a problem until this matter is resolved.

CONCLUSIONS

Based upon the above findings, the following conclusions have been reached by EPA:

(1) The best demonstrated systems of emissions control at the time the standard for primary emissions was established for BOPF have not changed in the past 5 years. (See APTD-1352c (EPA/2-74-003), Background Information for New Source Performance Standards, Volume 3, Promulgated Standards.) These technologies control emissions to a level consistent with the current standard; therefore, revision to the existing standard is not required, if only primary emissions are to be controlled.

(2) Secondary or fugitive emissions from BOPFs represent a major air pollution emission source. EPA, therefore, intends to initiate a project to revise the existing standard of performance to include fugitive emissions. This development project is planned to begin during 1979 and lead to a proposal 20 months after initiation. In addition, an assessment of foreign technology, which ahs been initiated by the Agency, will be included in the basis for the revised standard. The assessment may lead to further conclusions about the allowable emissions from the primary gas cleaning stack due to the interdependence of primary and secondary control technologies.

(3) The ambiguities in the present standard concerning definition of a BOPF and the operating cycle to be measured should be clarified, and a project to do so has been initiated.

PUBLIC PARTICIPATION

All interested persons are invited to comment on this review, the conclusions, and EPA's planned action. Comments should be submitted to: Mr. Don Goodwin (MD-13), Emission Standards and Engineering Division, U.S. Environmental Protection Agency, Research Triangle Park, N.C. 27711.

Dated: March 9, 1979.

BARBARA BLUM,
Acting Administrator.

[FR Doc. 79-8360 Filed 3-20-79; 8:45 am]

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

GLASS MANUFACTURING PLANTS

SUBPART CC

ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 60]

[FRL 1203-7]

Standards of Performance for New Stationary Sources; Glass Manufacturing Plants

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule and notice of public hearing.

SUMMARY: The proposed standards would limit emissions of particulate matter from new, modified, and reconstructed glass manufacturing plants. The standards implement the Clean Air Act and are based on the Administrator's determination that glass manufacturing plants contribute significantly to air pollution. The intended effect is to require new, modified, and reconstructed glass manufacturing plants to use the best demonstrated system of continuous emission reduction, considering costs, nonair quality health and environmental impact, and energy impacts.

A public hearing will be held to provide interested persons an opportuity for oral presentation of data, views, or arguments concerning the proposed standards.

DATES: *Comments.* Comments must be received on or before August 14, 1979.

Public Hearing. The public hearing will be held on July 9, 1979 beginning at 9:30 a.m. and ending at 4:30 p.m.

Request to Speak at Hearing. Persons wishing to present oral testimony at the hearing should contact EPA by June 29, 1979.

ADDRESSES: *Comments.* Comments should be submitted to Central Docket Section (A-130), United States Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460, Attention: Docket No. OAQPS 79-2.

Public Hearing. The public will be held at Office of Administration Auditorium, Research Triangle Park, North Carolina 27771. Persons wishing to present oral testimony should notify Mary Jane Clark, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Rsearch Triangle Park, North Carolina 27711, telephone (919) 541-5271.

Standards Support Document. The support document for the proposes standards may be obained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Glass Manufacturing Plants, Background Information: Proposed Standards of Performance," EPA-450/3-79-005a.

Docket. A docket, number OAQPS 79-2, containing information used by EPA in development of the proposed standard, is available for public inspection between 8:00 a.m. and 4:00 p.m. Monday through Friday, at EPA's Central Docket Section (A-130), Room 2903 B, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Proposed Standards

The standards would apply to glass melting furnaces with glass manufacturing plants with two exceptions: day pot furnaces (which melt two tons or less of glass per day) and all-electric melting furnaces. No existing plants would be covered unless they were to undergo modification or reconstruction. Change of fuel from gas to fuel oil would be exempt from consideration as a modification and rebricking of furnaces would be exempt from consideration as reconstruction.

Specifically, the proposed standards would limit exhaust emissions from gas-fired glass melting furnaces to 0.15 grams of particulate matter per kilogram of glass produced for flat glass production; 0.1 g/kg (0.2 lb/ton) for container glass production; 0.2 g/kg (0.4 lb/ton) for wool fiberglass production; 0.1 g/kg (0.2 lb/ton) for pressed and blown glass production of soda-lime formulation; and 0.25 g/kg (0.5 lb/ton) for pressed and blown glass production of borosilicate, opal, and other formulations. A 15 percent allowance above the emission limits for gas-fired furnaces is proposed for fuel oil-fired glass melting furnaces and an additional proportionate allowance is proposed for furnaces simultaneously firing gas and fuel oil.

Summary of Environmental and Economic Impacts

Environmental Impacts

The proposed standards would reduce projected 1983 emissions from new uncontrolled glass melting furnaces from about 5,200 megagrams (Mg)/year (5,732 ton/year) to about 400 Mg/year (441 ton/year). This is a reduction of about 92 percent of uncontrolled emissions. Meeting a typical State Implementation Plan (SIP), however, would reduce emissions from new uncontrolled furnaces by about 3,700 Mg/year (4,079 ton/year), or by about 70 percent. The proposed standard would exceed the reduction achieved under a typical SIP by about 1,100 Mg/year (1,213 ton-year). This reduction in emissions would result in a reduction of ambient air concentrations of particulate matter in the vicinity of new glass manufacturing plants.

The proposed standards are based on the use of electrostatic precipitators (ESP's) and fabric filters, which are dry control techniques; therefore, no water discharge would be generated and there would be no adverse water pollution impact.

The solid waste impact of the proposed standards would be minimal. Less than 2 Mg (2.2 ton) of particulate would be collected for every 1,000 Mg (1,102 ton) of glass produced. These dusts can generally be recycled, or they can be landfilled if recycling proves to be unattractive. The current solid waste disposal practice among most controlled plants surveyed is landfilling. Since landfill operations are subject to State regulation, this disposal method would not be expected to have an adverse environmental impact. The additional solid material collected under the proposed standard would not differ chemically from the material collected under a typical SIP regulation; therefore, adverse impact from landfilling should be minimal. Also, recycling of the solids has no adverse environmental impact.

For typical plants in the glass manufacturing industry, the increased energy consumption that would result from the proposed standards ranges from about 0.1 to 2 percent of the energy consumed to produce glass. The energy required in excess of that required by a typical SIP regulation to control all new glass melting furnaces constructed by 1983 to the level of the proposed standards would be about 2,500 kilowatt-hours per day in the fifth year and is considered negligible. Thus, the proposed standards would have a minimal impact on national energy consumption.

Economic Impacts

The economic impact of the proposed standards is reasonable. Compliance with the standards would result in annualized costs in the glass manufacturing industry of about $8.5 million by 1983. For typical plants constructed between 1978-1983 capital costs associated with the proposed

standards would range from about $235,000 for a small furnace in the pressed and blown glass sector which melts formulations other than soda-lime to about $770,000 for a large pressed and blown glass furnace which melts soda-lime formulations. Annualized costs associated with the proposed standards would range from about $70,000/year to about $235,000/year for the furnaces mentioned above. Cumulative capital costs of complying with the proposed standards for the glass manufacturing industry as a whole would amount to about $28 million between 1978–1983. The percent price increase necessary to offset costs of compliance with the proposed standards would range from about 0.3 percent in the wool fiberglass sector to about 1.8 percent in the container glass sector. Industry-wide, the price increase would amount to about 0.7 percent.

The economic impact of the proposed standards may vary depending on the size of the glass melting furnace being considered. EPA is requesting comments specifically on the economic impact of the proposed standards with regard to a possible lower cut-off size for glass melting furnaces.

Rationale

Selection of Source and Pollutants

The proposed Priority List, 40 CFR 60.16, identifies various sources of emissions on a nationwide basis in terms of the quantities of emissions from source categories, the mobility and competitive nature of each source category, and the extent to which each pollutant endangers health or welfare. The sources on this proposed list are ranked in decreasing order. Glass manufacturing ranks 38th on the proposed list, and is therefore of considerable importance nationwide.

The production of glass is projected to increase at compounded annual growth rates of up to 7 percent through the year 1983. In 1975, over 17 million megagrams (18.8 million ton) of glass were produced; by 1983 this production rate is expected to increase by nearly 2.9 million Mg/year (3.2 million ton/year). Geographically, the glass manufacturing industry is relatively concentrated with plants currently located in 17 states. Total particulate emissions in the United States in 1975 were estimated to be about 12.4 million Mg/year (13.7 million ton/year); by the year 1983 new glass manufacturing plants would cause annual nationwide particulate matter emissions to increase by about 1,500 Mg/year (1,620 ton/year) with emissions controlled to the level of a typical SIP regulation.

On March 18, 1977, the Governor of New Jersey petitioned EPA to establish standards of performance for glass manufacturing plants. The petition was primarily motivated by the Governor's concern that the glass manufacturing industry might locate plants in other States rather than comply with New Jersey's air pollution regulations limiting emissions of particulate matter. The glass manufacturing industry is not geographically tied to either markets or resources. Only a few States have specialized air pollution standards for glass manufacturing plants in their SIP's, and these standards vary in the level of control required. Therefore, new glass manufacturing operations could be located in States which do not have stringent SIP regulations.

Glass manufacturing plants are significant contributors to nationwide emissions of particulate matter, especially when viewed as contributors to emissions in the limited number of States in which they are located. They rank high with regard to potential reduction of emissions. Since they are free to relocate in terms of both markets and required resources, the possibility exists that operations could be moved or relocated to avoid stringent SIP regulations, thereby generating economic dislocations. For these reasons, emissions of particulate matter from new glass manufacturing plants have been selected for control by NSPS.

Glass manufacturing plants also emit other criteria pollutants: sulfur oxides (SO_x), nitrogen oxides (NO_x), carbon monoxide, and hydrocarbons. Carbon monoxide and hydrocarbon emissions from efficiently operated glass manufacturing plants, however, are negligible.

Nationwide, the largest aggregate emissions from glass manufacturing plants are NO_x. The techniques generally applicable to control NO_x produced by combustion are staged combustion, off-stoichiometric combustion, or reduced-temperature combustion. To date none of these techniques has been applied to the control of NO_x emissions from glass melting furnaces. Accordingly, there is no way of determining how effective they might be in such applications. Consequently, NO_x was not selected for control by standards of performance.

SO_x emissions result from combustion of sulfur-containing fuels and from chemical reactions of raw materials. In general there are two alternatives for control of SO_x emissions: (1) scrubbing of exhaust gases containing SO_x, and (2) reducing the sulfur content of fuel and raw materials. SO_x emissions from glass melting furnaces are in most cases already less than the emission limits of applicable SIP's for fuel burning sources. Flue-gas scrubbing for control of SO_x emissions from glass melting furnaces is not considered economically reasonable.

There are difficulties as well with the use of low-sulfur fuels or reduction of sulfur content of raw materials. Using low-sulfur fuel would not adequately address the problem of SO_x control for two reasons. Natural gas is the preferred fuel for glass melting furnaces. The only alternative fuel currently in use or projected for future use by the glass manufacturing industry is distillate fuel oil, which normally contains more sulfur than natural gas. The elimination of sulfur-containing fuel oil is not considered reasonable. Alternatively, standards of performance based solely on combustion of low-sulfur fuels could distort existing fuel distribution patterns, since low-sulfur fuels could be diverted to new facilities to meet NSPS in areas that have no difficulty attaining or maintaining the National Ambient Air Quality Standards (NAAQS) for SO_x. This would reduce the supply of low-sulfur fuels for existing facilities in areas that have great difficulty attaining or maintaining the NAAQS for SO_x. Consequently, standards of performance for SO_x emissions based on use of low-sulfur fuels do not seem reasonable.

Use of reduced-sulfur raw materials has not been demonstrated as a means of reducing SO_x emissions from glass melting furnaces. There is a wide variety of formulations, most of which are considered by the industry to be trade secrets. The present state of glass making is such that formula alterations of the type envisioned here would lead to glass of unpredictable quality. For these reasons, standards of performance for SO_x emissions from glass melting furnaces based on reduced-sulfur raw materials, or any other approach, do not seem reasonable and have not been proposed.

Selection of Affected Facility

Ninety-eight percent of the particulate matter emitted from glass manufacturing plants is emitted in gaseous exhaust streams from glass melting furnaces. Only two percent of the particulate matter emitted from glass manufacturing plants is emitted from raw material handling and glass forming and finishing. Therefore, the glass melting furnace has been selected as the affected facility.

The proposed standards would apply to all glass melting furnaces within glass manufacturing plants with two exceptions: day pot furnaces and all-electric melters. A day pot furnace is a glass melting furnace which is capable of producing no more than two tons of glass per day. These small glass melting furnaces constitute an extremely small percentage of total glass production and their control is not considered economically reasonable. Therefore, the regulation exempts day pot furnaces from the proposed standards.

Well operated and maintained all-electric furnaces have particulate emissions only slightly higher than fossil-fuel fired furnaces controlled to meet the proposed standards. Most of these furnaces are open to the atmosphere and do not have stacks. Thus, control and measurement of emissions from all-electric furnaces does not appear to be economically reasonable. Therefore, all-electric melting furnaces are not regulated by the proposed standards.

Selection of Format

Two alternative formats were considered for the proposed standards: mass standards, which limit emissions per unit of feed to the glass furnace or per unit of glass produced by the glass furnace; and concentration standards, which limit emissions per unit volume of exhaust gases discharged to the atmosphere.

Enforcement of concentration standards requires a minimum of data and information, decreasing the costs of enforcement and reducing chances of error. Furthermore, vendors of emission control equipment usually guarantee equipment performance in terms of the pollutant concentration in the discharge gas stream.

There is a potential for circumventing concentration standards by diluting the exhaust gases discharged to the atmosphere with excess air, thus lowering the concentration of pollutants emitted but not the total mass emitted. This problem can be overcome, however, by correcting the concentration measured in the gas stream to a reference condition such as a specified oxygen percentage in the gas stream.

Concentration standards would penalize energy-efficient furnaces, since a decrease in the amount of fuel required to melt glass decreases the volume of gases released but not the quantity of particulate matter emitted. As a result, the concentration of particulate matter in the exhaust gas stream would be increased even though the total mass emitted remained the same. Even if a concentration standard were corrected to a specified oxygen content in the gas stream, this penalizing effect of the concentration would not be overcome.

Primary disadvantages of mass standards, as compared to concentration standards, are that their enforcement is more costly and that the more numerous calculations required increase the opportunities for error. Detemining mass emissions requires the development of a material balance on process data concerning the operation of the plant, whether it be input flow rates or production flow rates. Development of this balance depends on the availability and reliability of production figures supplied by the plant. Gathering of these data increases the testing or monitoring necessary, the time involved, and, consequently, the costs. Manipulation of these data increases the number of calculations necessary; e.g., the conversion of volumetric flow rates to mass flow rates, thus compounding error inherent in the data and increasing the chance for error.

Although concentration standards involve lower resource requirements than mass standards, mass standards are more suitable for regulation of particulate emissions from glass melting furnaces because of their flexibility to accommodate process improvements and their direct relationship to quantity of particulate emitted to the atmosphere. These advantages outweigh the drawbacks associated with creating and manipulated a data base. Consequently, mass standards are selected as the format for expressing standards of performance for glass melting furnaces.

The proposed standards express allowable particulate emissions in grams of particulates per kilogram of glass pulled. While emissions data referring to raw material input as well as data referring to glass pulled were used in the development of the standards, an examination of the several sectors of the glass manufacturing industry indicated that an emission rate based on quantity of glass pulled would be more representative of industry practice. Further, emissions are more dependent on pull rate than on rate of raw material input. Accordingly, the mass of glass pulled is used as the denominator in the proposed standards. Raw material input data could be employed to estimate glass pulled from a furnace if a quantitative relationship between raw material input and glass pulled were developed following good engineering methods.

Selection of the Best System of Emission Reduction and Emission Limits

Introduction

Particulate emissions from glass melting furnaces can be reduced significantly by the use of the following emission control techniques: electrostatic precipitators, fabric filters, and venturi scrubbers. Since these emission control techniques do not achieve the same level of control for glass melting furnace emissions within all sectors of the glass manufacturing industry, they are discussed separately for each sector.

Process modifications such as batch formulation alteration and electric boosting also may be capable of reducing particulate emissions from glass melting furnaces. The test data available for furnaces where process modifications are used as emissions reduction techniques indicate that emission reduction by process modification is indifinite with respect to the effectiveness of the techniques. Accordingly, the selection of the best system of emission reduction is based on the use of add-on emission reduction techniques of known effectiveness. However, there is nothing in this proposal nor is it the intent of this proposal to preclude the use of process modifications to comply with the proposed standards.

The glass manufacturing industry is divided into four principal sectors designated by Standard Industrial Classifications (SIC's). The container glass sector (SIC 3221) manufactures containers for commercial packing and bottling and for home canning by pressing (stamping) and/or blowing (air-forming) molten glass usually of soda-lime recipe. The pressed and blown glass, not elsewhere classified, sector (SIC 3229) includes such diverse products as: table, kitchen, art and novelty glassware; lighting and electronic glassware; scientific, technical, and other glassware; and textile glass fibers. Based on the differing rates of particulate matter emissions, it is necessary to subdivide the pressed and blown glass sector into plants producing glass from soda-lime formulations and plants producing glass from other formulation (primarily borosilicate, opal and lead). Glass manufacturing plants in the wool fiberglass sector are classified under mineral wool (SIC 3296); fiberglass insulation is a major product. The flat glass sector (SIC 3211) uses continuous glass forming processes, and materials almost exclusively of soda lime

formulation, to manufacture sheet, plate, float, rolled, and wire glass.

Each of the glass manufacturing sectors is unique both from a technical and an economic standpoint. Thus, uncontrolled particulate emission rate, furnace size, and the applicability of emission control techniques vary from one sector to another. Since the products manufactured by the different sectors of the glass manufacturing industry serve different markets, each sector is working in a different economic environment. For these reasons it was apparent that no single model furnace could adequately characterize the glass manufacturing industry. Accordingly, several model furnaces were specified in terms of the following parameters: production rate, stack height, stack diameter, exhaust gas exit velocity, exhaust gas flow rate, and exhaust gas temperature. The evaluation of these parameters may be found in the Background Information document. The model furnace production rate specified for the container glass sector was 225 Mg/day (250 ton/day). For pressed and blown glass furnaces melting soda-lime and other formulations two model furnace production rates were specified: 45 Mg/day (50 ton/day) and 90 Mg/day (100 ton/day). Model furnace production rates for the wool fiberglass and flat glass sector were 180 Mg/day (200 ton/day) and 635 Mg/day (700 ton/day), respectively.

Review of the performance of the emission control techniques led to the identification of two regulatory options for each sector. These options specify numerical emission limits for glass melting furnaces in each sector of the glass manufacturing industry. The environmental impacts, energy impacts, and cost and economic impacts of each regulatory option were compared with those associated with a typical SIP regulation and those associated with no control.

Container Glass

Uncontrolled particulate emissions from container glass furnaces are generally about 1.25 g/kg (2.5 lb/ton) of glass pulled. Emission tests (using EPA Method 5) on three container glass furnaces equipped with ESP's indicate an average particulate emission of 0.06 g/kg (0.12 lb/ton) of glass pulled.

Emission test data for container glass furnaces equipped with fabric filters are not available. However, emission test results for a pressed and blown glass furnace melting a soda-lime formulation essentially identical to that used for container glass indicate that emissions can be reduced to 0.12 g/kg (0.24 lb/ton) of glass pulled with a fabric filter. This fabric filter installation was tested with the Los Angeles Air Pollution Control District particulate matter test method (LAAPCD Method), which considers the combined weight of the particulate matter collected in water-filled impingers and of that collected on a filter. EPA Method 5 also uses impingers and a filter, but considers only the weight of the particulate matter collected on the filter. The LAAPCD Method collects a larger amount of particulate matter than does EPA Method 5, and, consequently, greater mass emissions would be reported for comparable tests. An emission level of 0.1 g/kg (0.2 lb/ton) as determined by EPA Method 5, could be achieved by a container glass furnace equipped with a properly designed and operated fabric filter.

EPA Method 5 tests of four furnaces equipped with venturi scrubbers indicated an average particulate emission of 0.21 g/kg (0.42 lb/ton) of glass pulled.

Based on the data cited above, an emission level of 0.1 g/kg (0.2 lb/ton) of glass pulled from container glass furnaces can be achieved with ESP's or fabric filters. An emission level of 0.2 g/kg (0.4 lb/ton) of glass pulled can reasonably be achieved with a venturi scrubber when operated at a pressure drop somewhat higher than the average of those scrubbers tested. ESP's and fabric filters could also be designed to achieve an emission level of 0.2 g/kg (0.4 lb/ton) of glass pulled.

On the basis of these conclusions, two regulatory options for reducing particulate emissions from container glass furnaces were formulated. Option I would set an emission limit of 0.1 g/kg (0.2 lb/ton), requiring a particulate emission reduction of somewhat over 90 percent as compared with an uncontrolled furnace. Option II would set an emission limit of 0.2 g/kg (0.4 lb/ton), requiring a particulate emission reduction of about 85 percent.

By 1983 approximately 1900 gigagrams (Gg)/year (2.1 million ton/year) of additional production is anticipated in the container glass sector. About 25 new container glass furnaces of about 225 Mg/day (250 ton/day) production capacity (the size of the model furnace) would be built in order to provide this additional production. If uncontrolled, these new container glass furnaces would add about 2,400 Mg/year (2,646 ton/year) to national particulate emissions by 1983. Compliance with a typical SIP regulation would reduce this impact to about 1,000 Mg/year (1,102 ton/year). Under Option I, emissions would be reduced to about 19 percent of those emitted under a typical SIP regulation. Under Option II, emissions would be reduced to about 38 percent of those emitted under a typical SIP regulation.

Ambient dispersion modeling indicates that under worst case conditions the annual maximum ground-level particulate concentration near an uncontrolled container glass furnace producing 225 Mg/day of glass would be less than 1 $\mu g/m^3$. The annual maximum ground-level concentration resulting from compliance with a typical SIP regulation, Option I, or Option II would also be less than 1 $\mu g/m^3$. The calculated maximum 24-hour ground-level particulate concentration near an uncontrolled container glass furnace producing 225 Mg/day of glass would be approximately 10 $\mu g/m^3$. The corresponding concentration for complying with a typical SIP regulation would be 5 $\mu g/m^3$. Under Option I, with an ESP or a fabric filter being employed for control, the maximum 24-hour ground-level concentration would be reduced to 1 $\mu g/m^3$. Under Option II, with the same techniques being employed, the concentration would be reduced to 2 $\mu g/m^3$. Use of a venturi scrubber to meet the Option II emissions limit would only reduce the concentration to 6 $\mu g/m^3$ due to the decreased stack height of a scrubber-controlled plant and the resulting increased building wake effects.

With one exception, standards of performance for container glass furnaces would have no water pollution impact. The exception would be the use of a venturi scrubber to comply with a standard based on Option II. Such a system, applied to a furnace producing 225 Mg/day of glass, would discharge about 0.5 m^3/hr of waste water containing about 5 percent solids. The waste water would probably be discharged directly to an available waste water treatment system. To date, however, only a few container glass furnaces have been controlled with venturi scrubbers; dry collection techniques have been preferred. Consequently, few container glass manufacturers would be expected to install venturi scrubbers on their furnaces to comply with a standard based on Option II. The overall water pollution impact would then be negligible.

The potential solid waste impacts of the regulatory options would result from collected particulate matter. Solid waste from container glass furnaces, other than collected particulate matter, is minimal since cullet is normally

recycled back into the glass melting process. Under a typical SIP regulation, about 1,400 Mg/year (1,543 ton/year) of particulate matter would be collected from the 25 new 225 Mg/day container glass furnaces projected to come on-stream during the 1978–1983 period. Compliance with standards based on Option I and Option II would add about 800 Mg/year (882 ton/year) and about 600 Mg/year (661 ton/year), respectively, to the solid waste collected under a typical SIP regulation. Option I would increase the mass of solids for disposal by about 60 percent over that resulting from compliance with a typical SIP regulation, and Option II would increase it by about 45 percent. The additional solid material collected under Option I or Option II would not differ chemically from the material collected under a typical SIP regulation. Collected solids either are recycled back into the glass melting process or are disposed of in a landfill. Recycling of the solids has no adverse environmental impact, and, since landfill operations are subject to State regulation, this disposal method also would not be expected to have an adverse environmental impact.

The potential energy impacts of the regulatory options would be due to the energy used to drive the fans in emission control systems and the energy used to charge the electrodes in ESP's. Since ESP's have been the predominant control system used in the industry, the energy requirements estimated for a typical SIP regulation, Option I, and Option II were based on the use of ESP's. The energy required to control particulate emissions from the 25 new container glass furnaces would be about 40 million kWh (22 thousand barrels of oil/year) for a typical SIP regulation for the new furnaces equipped with ESP's. This required energy would be about 0.2 percent of the total energy use in the container glass sector. There would be no energy impact associated with either Option I or Option II because the energy required to operate an ESP for Option I or Option II is essentially the same as the energy required to operate an ESP for a typical SIP regulation.

Incremental installed cost (cost in excess of a typical SIP regulation cost) in January 1978 dollars associated with Option I for controlling particulate emissions from a 225 Mg/day container glass furnace would be about $700 thousand for an ESP and about $1.2 million for a fabric filter. Incremental installed cost associated with Option II would be about $450 thousand for an ESP, and about $1 million for a fabric filter. The incremental installed cost of control equipment associated with Option I level of control would be about 1.6 times the incremental installed cost associated with Option II if ESP's were selected. If fabric filters were selected, the incremental installed cost associated with the Option I level of control would be about 1.2 times the incremental installed cost associated with Option II.

Incremental annualized costs associated with Option I for a 225 Mg/day furnace would be about $200 thousand/year and about $350 thousand/year for an ESP and a fabric filter, respectively. Incremental annualized costs associated with Option II would be about $130 thousand/year for an ESP, and about $300 thousand/year for a fabric filter. The incremental annualized cost associated with Option I would be about 1.5 times the incremental annualized cost associated with Option II if ESP's were used. If fabric filters were used the incremental annualized cost associated with Option I would be about 1.2 times the incremental annualized cost associated with Option II.

Based on the use of control equipment with the highest annualized cost (worst case conditions), a price increase of about 1.8 percent would be necessary to offset the cost of installing control equipment on a 225 Mg/day container glass furnace to meet the emissions limit of Option I. A price increase of about 1.5 percent would be necessary to comply with the emission limit of Option II.

Incremental cumulative capital costs for the 25 new 225 Mg/day container glass furnaces during the 1978–1983 period associated with Option I would be about $17 million if ESP's were used. Use of ESP's to comply with a standard based on Option II would require incremental cumulative capital costs of about $11 million for the same period. Fifth-year annualized costs for controlling container glass melting furnaces to comply with Option I would be about $5 million/year. To comply with Option II, fifth-year annualized costs would be about $3 million/year.

A summary of incremental impacts (in excess of impacts of a typical SIP regulation) associated with Option I and Option II is shown in Table 1. Air impacts, expressed in Mg/year of particulate matter emissions reduced, would approximate the quantity of particulate matter collected and disposed of as solid waste.

Table 1.—*Summary of Incremental Impacts Associated With Regulatory Options*

	Impacts			
	Air [1]	Water	Energy [2]	Economic [3]
Regulatory option:				
I	800	None	Negligible	~1.8
II	600	Negligible	Negligible	~1.5

[1] Mg/Yr reduced.
[2] Barrels of oil/day
[3] Percent price increase.

Consideration of the beneficial impact on national particulate emissions, the degree of water pollution impact, the small potential for adverse solid waste impact, the lack of energy impact, the reasonableness of cost impact, and the general availability of demonstrated emission control technology leads to the selection of Option I as the basis for standards for glass melting furnaces in the container glass sector.

Pressed and Blown Glass—Soda-Lime Formulation

Because the glass production rates, the furnace configurations, and the glass formulations melted in furnaces in this sector are very similar to those in container glass sector, the quantity and chemical composition of particulate emissions approximate those of container glass furnaces. On the basis of this similarity of process and emissions, the emission reduction techniques which have been shown to be effective for container glass furnaces would also be effective in reducing particulate emissions from furnaces in this sector.

Uncontrolled particulate emissions from pressed and blown glass furnaces melting soda-lime formulations are generally about 1.25 g/kg (2.5 lb/ton) of glass pulled from the furnace. Test data for a pressed and blown glass furnace melting a soda-lime formulation and equipped with a fabric filter indicate particulate emissions of 0.12 g/kg (0.24 lb/ton) of glass pulled using the

LAAPCD Method. No emissions data for pressed and blown glass furnaces equipped with ESP's are available. However, emission tests using EPA Method 5 on three container-glass furnaces equipped with ESP's indicate an average particulate emission rate of 0.06 g/kg (0.12 lb/ton) of glass pulled. Because of the similarities between this sector and the container glass sector, both ESP's and fabric filters would be expected to be capable of reducing emissions to about 0.1 g/kg (0.2 lb/ton) of glass pulled.

Based on the similarity of pressed and blown glass production methods in this sector to those of the container glass sector, as well as on test data available on container glass furnace emissions, two regulatory options were formulated. The regulatory options are identical to those formulated for container glass furnaces. Option I would set an emission limit of 0.1 g/kg (0.2 lb/ton) of glass pulled, which would require a particulate emission reduction of about 90 percent. Option II would set an emission limit of 0.2 g/kg (0.4 lb/ton) of glass pulled, which would require about 85 percent particulate emission reduction.

By 1983 approximately 310 Mg/year (342 ton/year) of additional production is anticipated in this glass manufacturing sector. About four new 45 Mg/day (50 ton/day) (small) and six new 90 Mg/day (100 ton/day) (large) furnaces would be built in order to provide this production. Emissions from the large furnaces would have to be reduced in order to comply with a typical SIP regulation, while small furnaces would meet a typical SIP regulation without reducing emissions. If uncontrolled, the four new small furnaces would add about 80 Mg/year (88 ton/year) to national particulate emissions by 1983, while the six new large furnaces would add about 230 Mg/year (254 ton/year). Compliance with a typical SIP regulation would reduce the impact of the new large furnaces to about 70 Mg/year (77 ton/year). Under Option I, these furnace emissions would be reduced to about 26 percent of those emitted under a typical SIP regulation. Under Option II, large furnace emissions would be reduced to about 53 percent of those emitted under a typical SIP regulation.

The small furnaces would be in compliance with a typical SIP regulation without control. Under Option I, emissions would be reduced to about 8 percent of uncontrolled emissions. Under Option II, emissions would be reduced to about 16 percent of uncontrolled emissions.

The effect of a typical SIP regulation for both 90 Mg/day (100 ton/day) and 45 Mg/day (50 ton/day) furnaces would be a reduction of about 48 percent of uncontrolled emissions. Under Option I, emissions would be reduced to about 16 percent of those emitted under a typical SIP regulation. Under Option II, emissions would be reduced to about 33 percent of those emitted under a typical SIP regulation.

Ambient dispersion modeling indicates that under worst case conditions the annual maximum ground-level particulate concentration near an uncontrolled pressed and blown glass furnace producing 45 Mg/day of glass would be less than 1 $\mu g/m^3$, as would the concentrations resulting from compliance with Option I or Option II. Corresponding annual maximum ground-level concentrations near an uncontrolled pressed and blown glass furnace producing 90 Mg/day of glass would also be less than 1 $\mu g/m^3$. Emissions from uncontrolled furnaces of either size in this sector would result in calculated maximum 24-hour ground-level concentrations of 3 $\mu g/m^3$. Under Option I this concentration would be reduced to below 1 $\mu g/m^3$. Under Option II it would be reduced to about 1 $\mu g/m^3$.

Since fabric filters and electrostatic precipitators are likely to be the control systems installed on furnaces in this sector to comply with standards, there would be no water pollution impact associated with standards based on either Option I or Option II.

Under a typical SIP regulation, no particulate matter would be collected from the four new 45 Mg/day pressed and blown glass furnaces projected to come on-stream during the 1978–1983 period. The six new 90 Mg/day furnaces would collect about 160 Mg/year (176 ton/year) under a typical SIP regulation. For the six 90 Mg/day furnaces the amounts collected in addition to those collected through compliance with a typical SIP regulation would be about 50 Mg/year (55 ton/year) for Option I and about 33 Mg/year (36 ton/year) for Option II. Compliance with standards based on Option I and Option II would result in the collection of about 72 Mg/year (79 ton/year) and about 68 Mg/year (75 ton/year), respectively, of solid waste from the four 45 Mg/day furnaces. Option I would increase the mass of solids for disposal by 100 percent and by about 31 percent over that required by a typical SIP regulation for 45 Mg/day and 90 Mg/day furnaces, respectively. Option II would increase the mass of solids for disposal by 100 percent and 21 percent over that required by a typical SIP regulation for 45 Mg/day and 90 Mg/day furnaces, respectively. The total masses of solids for disposal collected from all new furnaces would be about 122 Mg/year (135 ton/year) and 101 Mg/year (111 ton/year) for Option I and Option II, respectively.

The additional solid material collected under Option I and Option II would not differ chemically from the material collected under a typical SIP regulation. Collected solids either are recycled back into the glass melting process or are disposed of in a landfill. Recycling of the solids has no adverse environmental impact, and, since landfill operations are subject to State regulation, this disposal method also would not be expected to have an adverse environmental impact.

Since the four new 45 Mg/day furnaces would be in compliance with a typical SIP regulation without add-on controls, there would be no associated energy requirement. The estimated energy required to control particulates emissions from the four new 45 Mg/day furnaces projected to come on-stream in the 1978–1983 period to the levels required by both Option I and Option II would be about 1.5 million kWh (900 barrels of oil/year). The energy required to control particulate emissions from the six new 90 Mg/day furnaces would be 4.4 million kWh (2,500 barrels of oil/year) for a typical SIP regulation, Option I, or Option II if ESP's were installed.

The energy required to comply with the emission limits of the regulatory options would be about 0.5 percent of the total energy use in this glass manufacturing sector. The energy impacts of both Option I and Option II are negligible (~3 barrels of oil/day) for the new 45 Mg/day furnaces. There would be no energy impact associated with either Option I or Option II for the new 90 Mg/day furnaces beyond the impact associated with the requirements to meet a typical SIP regulation.

Incremental installed costs in January 1978 dollars associated with Option I for controlling particular emissions from a 45 Mg/day pressed and blown glass furnace melting soda-lime formulations would be about $740 thousand for an ESP and about $710 thousand for a fabric filter. Incremental installed costs associated with Option II would be about $645 thousand for an ESP, and about $675 thousand for a fabric filter. The incremental installed costs of control equipment associated with the Option I level of control would be about 1.1 times the incremental installed costs associated with Option II if ESP's were selected. If fabric filters were selected the incremental installed costs associated with the Option I level of

control would be about 1.1 times the incremental installed costs associated with Option II.

Incremental annualized costs for a 45 Mg/day furnace associated with Option I would be about $230 thousand/year for both ESP's and fabric filters. Incremental annualized costs associated with Option II would be about $205 thousand/year for an ESP, and about $215 thousand/year for a fabric filter. The incremental annualized costs associated with Option I would be about 1.1 times the incremental annualized costs associated with Option II if ESP's were used. If fabric filters were used, the incremental annualized costs associated with Option I would be about 1.1 times the incremental annualized costs associated with Option II.

Based on the use of control equipment with the highest annualized costs (worse case conditions), a price increase of about 0.6 percent would be necessary to offset the costs of installing control equipment on a 45 Mg/day pressed and blown glass furnace melting soda-lime formulations to meet the emission limits of Option I. A price increase of about 0.5 percent would be necessary to comply with the emission limits of Option II.

Incremental cumulative capital costs for the 1978–1983 period associated with Option I for the four new 45 Mg/day furnaces would be about $2.8 million if a fabric filter were used. Use of an ESP to comply with Option II would require incremental cumulative capital costs of about $2.6 million for the same period. Fifth-year annualized costs for controlling the furnace to comply with Option I would be about $910 thousand. To comply with Option II, fifth-year annualized costs would be about $815 thousand.

Incremental installed costs in January 1978 dollars associated with Option I for controlling particulate emissions from a 90 Mg/day pressed and blown glass furnace melting soda-lime formulations would be about $615 thousand for an ESP and about $770 thousand for a fabric filter. Incremental installed costs associated with Option II would be about $450 thousand for an ESP, and about $680 thousand for a fabric filter. The incremental installed costs of control equipment associated with the Option I level of control would be about 1.4 times the incremental installed costs associated with Option II, if ESP's were selected. If fabric filters were selected the incremental installed costs associated with the Option I level of control would be about 1.1 times the incremental installed costs associated with Option II.

Incremental annualized costs for a 90 Mg/day furnace associated with Option I would be about $175 thousand/year and about $235 thousand/ year for an ESP and a fabric filter, respectively. Incremental annualized costs associated with Option II would be about $130 thousand/year for an ESP, and about $205 thousand/year for a fabric filter. The incremental annualized costs associated with Option I would be about 1.3 times the incremental annualized costs associated with Option II if ESP's were used. If fabric filters were used the incremental annualized costs associated with Option I would be about 1.1 times the incremental annualized costs associated with Option II.

Based on the use of control equipment with the highest annualized cost, a price increase of about 0.6 percent would be necessary to offset the costs of installing control equipment on the large pressed and blown glass furnace melting soda-lime formulations to meet the emission limits of Option I. A price increase of about 0.5 percent would be necessary to comply with the emission limits of Option II.

Incremental cumulative capital costs for the 1978–1983 period associated with Option I for the six new 90 Mg/day furnaces would be about $3.7 million if ESP's were used. Use of ESP's to comply with Option II would require incremental cumulative capital costs of about $2.7 million for the same period. Fifth-year annualized costs for controlling these glass melting furnaces to comply with Option I would be about $1.1 million. To comply with Option II, fifth-year annualized costs would be about $790 thousand.

A summary of incremental impacts (in excess of impacts of the typical SIP regulation) associated with Option I and Option II is shown in Table II for both small and large furnaces. Air impacts, expressed in Mg/year of particulate matter emissions reduced, would approximate the quantity of particulate matter collected and disposed of as solid waste.

Table II.—*Summary of Incremental Impacts Associated With Regulatory Options*

	Impacts			
	Air [1]	Water	Energy [2]	Economic [3]
I	122	None	−3.0	−0.6
II	101	None	−3.0	−0.5

[1] Mg/Yr. reduced.
[2] Barrels of oil/day.
[3] Percent price increase.

Consideration of the beneficial impact on national particulate emissions, the lack of water pollution impact, the small potential for adverse solid waste impact, the reasonableness of energy and costs impacts, and the general availability of demonstrated emission control technology leads to the selection of Option I as the basis for standards for pressed and blown glass furnaces melting soda-lime formulations.

Pressed and Blown Glass—Other Than Soda-Lime Formulations

Uncontrolled particulate emissions from furnaces in this sector are about 5 g/kg (10 lb/ton) of glass pulled. Emission tests using EPA Method 5 on four furnaces melting borosilicate formulations and equipped with ESP's yielded a representative emission rate of about 0.50 g/kg (1.0 lb/ton) of glass pulled. A single emission test using EPA Method 5 on an ESP-controlled furnace melting fluoride/opal formulations yielded an emission rate of 0.17 g/kg (0.34 lb/ton) of glass pulled. EPA Method 5 tests of six ESP-controlled furnaces melting lead glass yielded a representative emission rate of 0.12 g/kg (0.24 lb/ton) of glass pulled. A single EPA method 5 emission test of an ESP-controlled furnace melting potash-soda-lead glass yielded an emission rate of 0.03 g/kg (0.06 lb/ton) of glass pulled. An EPA method 5 emission test on a furnace equipped with a fabric filter and melting soda-lead-borosilicate glass produced an emission rate of 0.17 g/kg (0.34 lb/ton) of glass pulled.

Upon consideration of the data cited above, an emission limit of 0.25 g/kg (0.5 lb/ton) of glass pulled was identified as a reasonable limit for control for pressed and blown glass furnaces melting other than soda-lime formulations. This limit was selected for Option I; it provides for about 95 percent particulate removal. Option II would set an emission limit of 0.5 g/kg (1.0 lb/ton) of glass pulled, which provides for a particulate removal of about 90 percent. Fabric filters and ESP's could be designed to achieve the levels of emission reduction required by either regulatory option.

By 1983 approximately 70 Gg/year (77,200 ton/year) of additional production is anticipated in this sector. One 45 Mg/day (50 ton/day) (small) furnace and two 90 Mg/day (100 ton/day) (large) furnaces would be built in order to provide this production. If uncontrolled, emissions from the one new small pressed and blown glass furnace melting formulations other than soda-lime would add about 90 Mg/year (100 ton/year) to national particulate

emissions by 1983, while the emissions from the two new large furnaces would add about 260 Mg/year (287 ton/year) during the same period.

Compliance with a typical SIP regulation would reduce the impact from the small furnace to about 27 Mg/year (30 ton/year). Control to the Option I emissions limit would reduce the emissions to about 17 percent of those emitted under a typical SIP regulation. With Option II emissions would be reduced to about 33 percent of those emitted under a typical SIP regulation.

Compliance with a typical SIP regulation would reduce the impact of the large furnances to about 47 Mg/year (52 ton/year). Under Option I, these emissions would be reduced to about 28 percent of those emitted under a typical SIP regulation. Under Option II, the large furnace emissions would be reduced to about 56 percent of those emitted under a typical SIP regulation.

The effect of a typical SIP regulation for both large and small furnaces would be a reduction of about 79 percent. Under Option I, emissions would be reduced to about 25 percent of those emitted under a typical SIP regulation. Under Option II, emissions would be reduced to about 50 percent of those emitted under a typical SIP regulation.

Ambient dispersion modeling indicates that under worst case conditions the annual maximum ground-level particulate concentration near an uncontrolled 45 Mg/day pressed and blown glass furnace melting formulations other than soda-lime would be less than 1 $\mu g/m^3$, as would be the concentrations resulting from compliance with a typical SIP regulation, Option I, or Option II. Corresponding annual maximum ground-level concentrations near a 90 Mg/day furnace also would be less than 1 $\mu g/m^3$.

The calculated maximum 24-hour ground-level concentration near an uncontrolled 45 Mg/day furnace in this sector would be 11 $\mu g/m^3$. This concentration would be reduced to 3 $\mu g/m^3$ with a typical SIP regulation. With Options I and II, the concentrations would be reduced to 1 $\mu g/m^3$ or less. The calculated maximum 24-hour ground-level concentration near an uncontrolled 90 Mg/day furnance would be 14 $\mu g/m^3$. This concentration would be reduced to 3 $\mu g/m^3$ with a typical SIP regulation and to below 1 $\mu g/m^3$ with Option I; with Option II it would reach 2 $\mu g/m^3$.

Since fabric filters and ESP's are likely to be the control systems installed on furnaces in this sector to comply with standards, there would be no water pollution impact associated with standards based on either Option I or Option II.

Under a typical SIP regulation, about 64 Mg/year (71 ton/year) of particulate matter would be collected from the one new 45 Mg/day furnace projected to come on-stream in the 1978–1983 period. Compliance with standards based on Option I and Option II would add about 23 Mg/year (25 ton/year) and 18 Mg/year (20 ton/year), respectively, to the solid waste collected under a typical SIP regulation. Option I would increase the mass of solids by about 36 percent over that resulting from compliance with a typical SIP regulation, and Option II would increase it by about 28 percent.

Under a typical SIP regulation, about 210 Mg/year (232 ton/year) of particulate matter would be collected from the two new 90 Mg/day furnaces projected to come on-stream in the 1978–1983 period. Compliance with standards based on Option I and Option II would add about 34 Mg/year (38 ton/year) and 21 Mg/year (23 ton/year), respectively, to the solid waste collected under a typical SIP regulation. Option I would increase the mass of solids by about 16 percent over that resulting from compliance with a typical SIP regulation, and Option II would increase it by about 10 percent. The total mass of solids for disposal collected from all three new furnaces in this sector, associated with Option I and Option II, would be about 57 Mg/year (63 ton/year) and about 39 Mg/year (43 ton/year), respectively.

The additional solid material collected under Option I or Option II would not differ chemically from the material collected under the typical SIP regulation. Collected solids either are recycled back into the glass melting process or are disposed of in a landfill. Recycling of the solids has no adverse environmental impact, and, since landfill operations are subject to State regulation, this disposal method also is not expected to have an adverse environmental impact.

Since ESP's have been the predominant control system used in the industry and are anticipated as the predominant system to be used for new plants coming on-stream between 1978–1983 regardless of which regulatory option is selected, energy requirements estimated for the typical SIP regulation, Option I, and Option II are based on the use of ESP's.

The energy required to control particulate emissions from the new 45 Mg/day pressed and blown glass furnace melting formulations other than soda-lime to the level required by the typical SIP regulation would be about 2.7 million kWh (1,500 barrels of oil/year). The energy required to comply with the Option I and Option II emissions limits would be essentially the same as that required for meeting a typical SIP regulation.

Control to the level required by a typical SIP regulation of the two new 90 Mg/day pressed and blown glass furnaces melting formulations other than soda-lime and projected to come on-stream during the 1978–1983 period would require about 6.6 million kWh (3,700 barrels of oil/year) if an ESP were used. The energy requirements to achieve the Option I and Option II emission limits would be essentially the same as the requirements for meeting a typical SIP regulation.

The energy required to comply with the emission limits of the regulatory options would be about 0.1 percent of total energy use for all new furnaces in this glass manufacturing sector. Considering the small amounts of additional oil and electricity required and the slight increase in total energy use in this sector, the energy impacts of either Option I or Option II would be negligible.

Incremental installed costs in January 1978 dollars associated with Option I for controlling particulate emissions from a 45 Mg/day pressed and blown glass furnace melting formulations other than soda-lime would be about $760 thousand for an ESP and about $235 thousand for a fabric filter. Incremental installed costs associated with Option II would be about $320 thousand for an ESP, and about $190 thousand for a fabric filter. The incremental installed costs of control equipment associated with the Option I level of control would be about 2.4 times the incremental installed costs associated with Option II if ESP's were selected. If fabric filters were selected the incremental installed costs associated with the Option I level of control would be about 1.2 times the incremental installed costs associated with Option II level of control.

Incremental annualized costs for a 45 Mg/day furnace assoicated with Option I would be about $230 thousand/year and about $70 thousand/year for an ESP and a fabric filter, respectively. Incremental annualized costs associated with Option II would be about $95 thousand/year for an ESP, and about $60 thousand/year for a fabric filter. The incremental annualized costs associated with Option I would be about 2.4 times the incremental annualized costs associated with Option II if ESP's were used. If fabric filters were used the incremental annualized costs associated

with Option I would be about 1.2 times the incremental annualized costs associated with Option II.

Based on the use of control equipment with the highest annualized costs (worse case conditions), a price increase of about 0.4 percent would be necessary to offset the costs of installing control equipment on a 45 Mg/day pressed and blown glass furnace melting other than soda-lime formulations to meet the emission limits of Option I. A price increase of about 0.3 percent would be necessary to comply with the emission limits of Option II.

Incremental cumulative capital costs for the 1978–1983 period associated with Option I for the 45 Mg/day furnace would be about $235 thousand if an ESP were used. Use of an ESP to comply with Option II would require incremental cumulative capital costs of about $190 thousand for the same period. Fifth-year annualized costs for controlling this furnace in this sector to comply with Option I would be about $70 thousand. To comply with Option II, fifth-year annualized costs would be about $60 thousand.

Incremental installed costs in January 1978 dollars associated with Option I for controlling particulate emissions from a 90 Mg/day pressed and blown glass furnace melting other than soda-lime formulations would be about $800 thousand for an ESP and about $260 thousand for a fabric filter. Incremental installed costs associated with Option II would be about $140 thousand for an ESP, and about $180 thousand for a fabric filter. The incremental installed costs of control equipment associated with the Option I level of control would be about 5.7 times the incremental installed costs associated with Option II if ESP's were selected. If fabric filters were selected the incremental installed costs associated with the Option I level of control would be about 1.4 times the incremental installed costs associated with Option II.

Incremental annualized costs for a 90 Mg/day furnace associated with Option I would be about $245 thousand per year and about $85 thousand per year for an ESP and a fabric filter, respectively. Incremental annualized costs associated with Option II would be about $45 thousand per year for an ESP, and about $55 thousand per year for a fabric filter. The incremental annualized costs associated with Option I would be about 5.4 times the incremental annualized costs associated with Option II if ESP's were used. If fabric filters were used the incremental annualized costs associated with Option I would be about 1.5 times the incremental annualized costs associated with Option II.

Based on the use of control equipment with the highest annualized costs, a price increase of about 0.8 percent would be necessary to offset the costs of installing control equipment on the 90 Mg/day pressed and blown glass furnace melting formulations other than soda-lime to meet the emission limits of Option I. A price increase of about 0.5 percent would be necessary to comply with the emission limits of Option II.

Incremental cumulative capital costs for the 1978–1983 period associated with Option I for the two new 90 Mg/day furnaces would be about $500 thousand if fabric filters were used. Use of ESP's to comply with Option II would require incremental cumulative capital costs of about $300 thousand for the same period. Fifth-year annualized costs for controlling these glass melting furnaces to comply with Option I would be about $160 thousand. To comply with Option II, fifth-year annualized costs would be about $85 thousand.

A summary of incremental impacts (in excess of impacts of the typical SIP regulation) associated with Option I and Option II is shown in Table III for both small and large furnaces. Air impacts, expressed in Mg/year of particulate matter emissions reduced, would approximate the quantity of particulate matter collected and disposed of as soild waste.

Table III.—*Summary of Incremental Impacts Associated With Regulatory Options*

	Impacts			
	Air[1]	Water	Energy[2]	Economic[3]
Regulatory option:				
I	57	None	Negligible	~0.7
II	39	None	Negligible	~0.4

[1] Mg/Yr reduced.
[2] Barrels of oil/day.
[3] Percent price increase.

Consideration of the beneficial impact on national particulate emissions, lack of water pollution impact, the small potential for adverse solid waste impact, the lack of energy impact, the reasonableness of cost impacts, and the general availability of demonstrated emission control technology leads to the selection of Option I as the basis for standards for pressed and blown glass furnaces melting formulations other than soda-lime.

Wool Fiberglass

Uncontrolled particulate emissions from wool fiberglass furnaces are generally about 5 g/kg (10 lb/ton) of glass pulled. The average emission from three furnaces in the wool fiberglass sector equipped with ESP's was 0.18 g/kg (0.36 lb/ton) of glass pulled. EPA Method 5 tests of three furnaces equipped with fabric filters indicated emissions of 0.2 g/kg (0.4 lb/ton), 0.26 g/kg (0.52 lb/ton), and 0.55 g/kg (1.1 lb/ton) of glass pulled. The test data cited indicate that an emission limit of 0.2 g/kg (0.4 lb/ton) of glass pulled could be met through the use of an ESP and that a limit of 0.4 g/kg (0.8 lb/ton) of glass pulled could be met through the use of either an ESP or a fabric filter.

On the basis of these conclusions, two regulatory options for reducing particulate emissions from wool fiberglass furnaces were formulated. Option I would set an emission limit of 0.2 g/kg (0.4 lb/ton) of glass pulled, which would provide for about 95 percent particulate removal. Option II would set an emission limit of 0.4 g/kg (0.8 lb/ton) of glass pulled, which would provide for about 90 percent removal of particulates.

By 1983 approximately 360 Gg/year (397,000 ton/year) of additional production is anticipated in the wool fiberglass sector. About six new wool fiberglass furnaces of about 180 Mg/day (200 ton/day production capacity (the size of the model furnace) would be built in order to provide this additional production. If uncontrolled, these new wool fiberglass furnaces would add about 1,800 Mg/year (1,984 ton/year) to national particulate emissions by 1983. Compliance with a typical SIP regulation would reduce this impact to about 210 Mg/year (232 ton/year). Under Option I, emissions would be reduced to about 33 percent of those emitted under a typical SIP regulation. Under Option II, emissions would be reduced to about 66 percent of those emitted under a typical SIP regulation.

Ambient dispersion modeling indicates that under worst case conditions the annual maximum ground-level particulate concentration near an uncontrolled wool fiberglass furnace producing 180 Mg/day of glass would be about 2 $\mu g/m^3$. The annual maximum ground-level concentrations resulting from compliance with a typical SIP regulation, Option I, or Option II would be less than 1 $\mu g/m^3$. The calculated maximum 24-hour ground-level particulate concentration near an uncontrolled wool fiberglass furnace producing 180 Mg/day of glass would be about 29 $\mu g/m^3$. The corresponding concentration for complying with a typical SIP regulation would be about 3 $\mu g/m^3$. Under Option I, with an ESP employed for control, the maximum 24-

...ground level concentration would be reduced to 2 μg/m³. Under Option II it would be reduced to 3 and 4 μg/m³ with the fabric filter and ESP, respectively.

Since fabric filters and ESP's are likely to be the control systems installed in wool fiberglass furnaces to comply with standards, there would be no water pollution impact associated with standards based on either Option I or Option II.

...

...

...

consistency, therefore, Option II would set an emission limit of 0.3 g/kg (0.6 lb/ton) of glass pulled, which would provide about 80 percent control.

By 1983 approximately 240 Gg/year (264,555 ton/year) of additional production is expected in the flat glass sector. One new flat glass furnace of about 635 Mg/day (700 ton/day) capacity (the size of the model furnace) would be built in order to provide this additional production.

If uncontrolled, this new flat glass furnace would add about 360 Mg/year (397 ton/year) to national particulate emissions by 1983. Compliance with a typical SIP regulation would reduce this impact to about 90 Mg/year (100 ton/year). Under Option I, emissions would be reduced to about 40 percent of those emitted under a typical SIP regulation. Under Option II, emissions would be reduced to about 80 percent of those emitted under a typical SIP regulation.

Ambient dispersion modeling indicates that under worst case conditions the annual maximum ground-level particulate concentration near an uncontrolled flat glass furnace producing 635 Mg/day of glass would be about 1 $\mu g/m^3$. The annual mazimum ground-level concentrations resulting from compliance with a typical SIP regulation, Option I, or Option II, would be less than 1 $\mu g/m^3$. The calculated maximum 24-hour ground-level particulate concentration near an uncontrolled flat glass furnace producing 635 Mg/day of glass would be about 21 $\mu g/m^3$. The corresponding concentration for complying with a typical SIP regulation would be about 5 $\mu g/m^3$. Under Option I, this concentration would be reduced to about 2 $\mu g/m^3$. Under Option II it would be reduced to about 5 $\mu g/m^3$.

Since the ESP is likely to be the emission control system installed on flat glass furnaces to comply with standards, there would be no water pollution impact associated with standards based on either Option I or Option II.

Under a typical SIP regulation, about 270 Mg/year (298 ton/year) of particulate matter would be collected from the one new 635 Mg/day flat glass furnace projected to come on-stream in the 1978–1983 period. Compliance with standards based on Option I and II would add about 50 Mg/year (55 ton/year) and about 20 Mg/year (22 ton/year), respectively, to the solid waste collected under a typical SIP regulation. Option I would increase the mass of solids for disposal by about 20 percent over that resulting from compliance with a typical SIP regulation, and Option II would increase it by about 7 percent. The additional solid material collected under Option I or Option II would not differ chemically from the material collected under a typical SIP regulation. Collected solids either are recycled back into the glass melting process or are disposed of in a landfill. Recyling of the solids has no adverse environmental impact, and, since landfill operations are subject to State regulations, this disposal method also is not expected to have an adverse environmental impact.

Since the energy requirements for an electrostatic precipitator do not vary significantly over the range of emission reductions considered here, the estimate of energy required to control particulate emissions from the one new flat glass furnace would be about the same for compliance with a typical SIP regulation, Option I, or Option II—about 7.6 million kWh (4,300 barrels of oil/year). The energy required to comply with the emission limits of the regulatory options would be about 0.2 percent of the total energy use in the flat glass sector. There would be no incremental energy impact associated with either Option I or Option II as compared with a typical SIP regulation.

The incremental installed cost in January 1978 dollars associated with Option I for controlling particulate emissions from a 635 Mg/day flat glass furnace would be about $605 thousand. Incremental installed cost associated with Option II would be about $140 thousand. The incremental installed cost of control equipment associated with the Option I level of control would be somewhat more than four times the incremental installed cost associated with the Option II level of control.

Incremental annualized cost associated with Option I for a 635 Mg/day flat glass furnace would be about $190 thousand/year; the corresponding incremental annualized cost for Option II would be about $45 thousand/year. The incremental annualized cost associated with Option I would be more than four times the incremental annualized cost associated with Option II.

A price increase of about 0.4 percent would be necessary to offset the cost of installing as ESP on a 635 Mg/day flat glass furnace to meet the emission limit of Option I. A price increase of about 0.1 percent would be necessary to comply with the emission limit of Option II.

Incremental cumulative capital cost for the one new 635 Mg/day flat glass furnace during the 1978–1983 period associated with Option I would be about $605 thousand. Compliance with Option II would require an incremental cumulative capital cost of about $145 thousand for the same period. Fifth-year annualized costs for controlling the one new flat glass furnace to comply with Option I would be about $190 thousand. To meet the Option II emissions limit, fifth-year annualized costs would be about $45 thousand.

A summary of incremental impacts associated with Option I and Option II is shown in Table V. Air impacts, expressed in Mg/year of particulate matter emissions reduced, would approximate the quantity of particulate matter collected and disposed of as solid waste.

Table V.—*Summary of Incremental Impacts Associated With Regulatory Options*

	Impacts			
	Air[1]	Water	Energy[2]	Economic[3]
Regulatory option.				
I	820	None	Negligible	—0.4
II	290	None	Negligible	—0.1

[1] Mg/Yr. reduced.
[2] Barrels of oil/day.
[3] Percent price increase.

Consideration of the beneficial impact on national particulate emissions, the lack of water pollution impact, the small potential for adverse solid waste impact, the lack of energy impact, the reasonableness of cost impacts, and the general availability of demonstrated emission control technology leads to the selection of the Option I as the basis for standards for glass melting furnaces in the flat glass sector.

Summary

If uncontrolled, total particulate emissions from the 45 new glass melting furnaces projected to come on-stream between 1978 and 1983 would be about 5,200 Mg/year (5,732 ton/year). Compared to a typical SIP regulation, Option I would reduce particulate emissions by an additional 1,100 Mg/year (1,213 ton/year).

Ambient dispersion modeling indicates that the annual maximum ground-level particulate concentrations near uncontrolled glass melting furnaces would be 2 $\mu g/m^3$ or less. Both a typical SIP regulation and the Option I emission limits would reduce the annual maximum ground-level particulate concentrations to under 1 $\mu g/m$. The 24-maximum ground-level particulate concentrations near uncontrolled glass melting furnaces would be less than 30 $\mu g/m^3$, with a median concentration of about 11 $\mu g/m^3$. Under a typical SIP regulation these concentrations would be reduced to 5 $\mu g/m^3$ or less. Control to the Option I emission limits would

reduce the 24-hour maximum ground-level concentrations near glass melting furnaces to about 2 $\mu g/m^3$ or less.

The glass manufacturing process has minimal water pollution potential. Complying with a standard based on Option I would have a negligible water pollution impact, because control systems installed to meet Option I would not discharge waste water streams.

The amounts of solid waste generated in the control of particulates from glass melting furnaces would approximate the amount of particulate removed from exhaust gases. Compliance with a typical SIP regulation would produce 3,700 Mg (4,080 tons) of solid waste per year. Meeting the Option I emission limits would generate an additional 1,100 Mg/year (1,213 ton/year). Either recycling or landfilling would present minimal adverse environmental impact. Totally recycling the collected solids would have no adverse impact. Landfilling operations must meet State regulations, and therefore this disposal method would have limited potential for adverse environmental impact.

Implementing Option I would require about 1.6 million kWh of electricity to power the emission control equipment installed above the requirements for implementing a typical SIP regulation. To meet this power requirement electric utilities would require about 950 barrels of oil/year, or about 3 barrels/day. The energy that would be required to operate emission reduction sytems to meet a standard based on the Option I limits would be 2 percent or less of the total energy used in glass production.

Incremental cumulative capital costs to the glass manufacturing industry for controlling emissions from new glass melting furnaces projected to come on-stream during the 1978–1983 period to comply with a standard based on the Option I emission limits would be about $27.9 million. The fifth-year annualized costs to the glass manufacturing industry associated with compliance with the Option I emission limits would be about $8.4 million. An industry-wide price increase of about 0.7 percent would be necessary to offset the costs of installing control equipment to meet the emission limits of Option I.

Modification, Reconstruction, and Other Considerations

An exemption from provisions of the modification section (40 CFR § 60.14) is proposed for those plants which convert to fuel-oil firing, even though particulate emissions would more than likely be increased. The primary objective of the proposed standards is to control emissions of particulates from glass melting furnaces. The data and information supporting the standards consider essentially only those emissions arising from the basic melting process, not those arising from fuel combustion. It is not the prime purpose of these standards, therefore, to control emissions from fuel combustion per se. Consequently, since emissions from fuel combustion are small in comparison with those from the basic melting process, and a conversion of glass melting furnaces to firing oil rather than natural gas will aid in efforts to conserve natural gas resources, the standards proposed herein include a provision exempting fuel switching in glass melting furnaces from consideration as a modification. The proposed increment in emissions allowed fuel oil-fired glass melting furnaces is 15 percent, a small allowance; however, without this exemption there would be a large economic impact on the industry.

An exemption from reconstruction provisions (40 CFR § 60.15) is proposed for the cold refining (rebricking) of the melter of an existing furnace. Under 40 CFR § 60.15 the Administrator must be notified of intent to conduct such a procedure 60 days in advance of commencement, and will determine whether or not the rebricking constitutes a reconstruction. This rebricking procedure has been a routine operation in the glass manufacturing industry and would not generally be considered an opportunity to evade the provisions of the standard by unduly extending the useful life of an existing glass melting furnace. Therefore, the exemption of rebricking from reconstruction provision has been proposed.

Glass melting furnaces fired with number 2 fuel oil would be expected to exhibit a 10 percent increase in particulate emissions over those produced in gas-fired furnaces since particulates are formed by the combustion of oil. Similarly, furnaces fired with numer 4, 5, or 6 fuel oil would show a 15 percent increase in particulate emissions over those produced in gas-fired furnaces. This effect of fuel oil on furnace emissions being recognized, it is proposed that the emission limits for furnaces fired with fuel oil be the limits for gas-fired furnaces multiplied by 1.15. It is additionally proposed that simultaneously liquid and gas-fired furnaces have emission limits based on an equation, taking into consideraton the relative proportions of the fuels being fired.

Selection of Performance Test Methods

The use of EPA Reference Method 5—"Determination of Particulate Emissions from Stationary Sources" (Appendix A, 40 CFR § 60, **Federal Register**, December 23, 1971) is required to determine compliance with the mass standards for particular matter emissions. Emission test data used in the development of the proposed standard were obtained either by the LAAPCD sampling method or by EPA Method 5. However, results of performance tests using Method 5 conducted by EPA on existing glass melting furnaces comprise a major portion of the data base used in the development of the proposed standard. EPA Reference Method 5 has been shown to provide a respresentative measurement of particulate matter emissions. Therefore, it has been included for determining compliance with the proposed standards.

Calculations applicable under Method 5 necessitate the use of data obtained from three other EPA test methods conducted previous to the performance of Method 5. Method 1—"Sample and Velocity Traverse for Stationary Sources" must be conducted in order to obtain representative measurements of pollutant emissions. The average gas velocity in the exhaust stack is measured by conducting Method 2—"Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)." The analysis of gas composition is measured by conducting Method 3—"Gas Analysis for Carbon Dioxide, Oxygen, Excess Air and Dry Molecular Weight." These three tests provide data necessary in Method 5 for converting volumetric flow rate to mass flow rate. In addition, Method 4—"Determination of Moisture Conent in Stack Gases" is suggested as an accurate mode of predetermination of moisture content.

Since the proposed standards are expressed as mass of emissions per unit mass of glass pulled, it will be neccessary to quantify glass pulled in addition to measuring particulate emissions. Glass production in Mg shall be determined by direct measurement or computed from materials balance data using good engineering practices. The materials balance computation may consist of a process relationship between feed material input rate and the glass pull rate. In all materials balance computations, glass pulled from the furnace shall include product, cullet, and any waste glass. The hourly glass pull rate for a furnace shall be determined by averaging the glass pull rate over the time of the performance test.

Selection of Monitoring Requirements

To provide a convenient means for enforcement personnel to ensure that installed emission control systems comply with standards of performance through proper operation and maintenance, monitoring requirements are generally included in standards of performance. For glass melting furnaces the most straightforward means of ensuring proper [illegible] and maintenance is to monitor emissions released to the atmosphere. EPA has established [illegible] performance [illegible] in Appendix B of 40 CFR [illegible] for [illegible] which [illegible] [illegible] [illegible]

111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

EPA will review this regulation four years from the date of promulgation. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, and improvements in emission control technology.

An economic impact assignment has been prepared as required under Section 317 of the Act and is included in the Background Information Document.

Dated: May 22, 1979

Douglas M. Costle,

Administrator.

It is proposed to amend Part 60 of Chapter I, Title 40 of the Code of Federal Regulations as follows:

Subpart CC—Standards of Performance for Glass Manufacturing Plants

Sec.

60.290 Applicability and designation of affected facility
60.291 Definitions.
60.292 Standards for particulate matter
60.293 Test methods and procedures.

Authority: Sections 111 and 301(a) of the Clean Air Act, as amended [42 U.S.C. 7411, 7601(a)], and additional authority as noted below.

§ 60.290 Applicability and designation of affected facility.

The affected facility to which the provisions of this subpart apply is each glass melting furnace within a glass manufacturing plant.

§ 60.291 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A.

(a) "Glass manufacturing plant" means any plant which produces glass or glass products.

(b) "Glass melting furnace" means a unit comprising a refractory vessel in which raw materials are charged, melted at high temperature, refined, and conditioned to produce molten glass. The unit includes foundations, superstructure and retaining walls, raw material charger systems, heat exchangers, melter cooling system, exhaust system, refractory brick work, fuel supply and electrical boosting equipment, integral control systems and instrumentation, and appendages for conditioning and distributing molten glass to forming apparatuses.

(c) "Day pot" means any glass melting furnace designed to produce less than 1800 kilograms of glass per day.

(d) "All-electric melter" means a glass melting furnace in which all the heat required for melting is provided by electric current from electrodes submerged in the molten glass, although some fossil fuel may be charged to the furnace as raw material.

(e) "Glass" means flat glass, container glass; pressed and blown glass; and wool fiberglass.

(f) "Flat glass" means glass made of soda-lime recipe and produced into continuous flat sheets and other products listed in Standard Industrial Classification 3211 (SIC 3211).

(g) "Container glass" means glass made of soda-lime recipe, clear or colored, which is pressed and/or blown into bottles, jars, ampoules, and other products listed in SIC 3211.

(h) "Pressed and blown glass" means glass which is pressed and/or blown, including textile fiberglass, noncontinuous process flat glass, noncontainer glass, and other products listed in SIC 3229. It is separated into:

(1) Glass of soda-lime recipe; and

(2) Glass of borosilicate, opal, lead and other recipes.

(i) "Wool fiberglass" means fibrous glass of random texture, including fiberglass insulation, and other products listed in SIC 3296.

(j) "Recipe" means formulation of raw materials.

(k) "Glass production" means the weight of glass pulled from a glass melting furnace.

(l) "Rebricking" means cold replacement of damaged or worn refractory parts of the glass melting furnace. Rebricking includes replacement of the refractories comprising the bottom, sidewalls, or roof of the melting vefssel; replacement of refractory work in the heat exchanger; replacement of refractory portions of the glass conditioning and distribution system.

(m) "Soda-lime recipe" means raw material formulation of the following approximate proportions: 72 percent silica; 15 percent soda; 10 percent lime and magnesia; 2 percent alumina; and 1 percent miscellaneous materials.

§ 60.292 Standards for particulate matter.

(a) On or after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator of a glass melting furnace subject to the provisions of this subpart shall cause to be discharged into the atmosphere, except as provided in paragraph (d) of this section:

(1) From any glass melting furnace, fired with a gaseous fuel, particulate matter at emission rates exceeding those specified in Table CC-1.

(2) From any glass melting furnace, fired with a liquid fuel, particulate matter at emission rates exceeding 1.15 times those specified in Table CC-1.

(3) From any glass melting furnace, simultaneously fired with gaseous and liquid fuel, particulate matter at emission rates exceeding those specified by the following equation:

$STD = X[1.15(Y) + (Z)]$

where:

STD = Particulate matter emission limit
X = Emission rate specified in Table CC-1
Y = Decimal percent of liquid fuel heating value to total (gaseous and liquid) fuel heating value

kilojoules

kilojoules

$Z = (1 - Y)$

(b) Conversion of a glass melting furnace to use of liquid fuel shall not be considered a modification for purposes of 40 CFR 60.14.

(c) Rebricking and the cost of rebricking shall not be considered reconstruction for the purposes of 40 CFR 60.15.

(d) This subpart shall not apply to day pots and all-electric melters.

Table CC-1—*Emission Rates*

Glass category	g of particulate/kg of glass produced
(1) Flat Glass	0.15
(2) Container Glass	.10
(3) Pressed and Blown Glass	
(a) Other than soda-lime recipes (i.e., borosilicate, opal, lead, and other recipes, including textile fiberglass)	.25
(b) Soda-lime recipes	.10
(4) Wool Fiberglass	.20

§ 60.293 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided under § 60.8(b), shall be used to determine compliance with § 60.292 as follows:

(1) Method 5 shall be used to determine the concentration of particulate matter and the associated moisture content.

(2) Method 1 shall be used for sample and velocity traverses, and

(3) Method 2 shall be used to determine velocity and volumetric flow rate.

(4) Method 3 shall be used for gas analysis.

(b) For Method 5, the sample probe and filter holder shall be heated to 121°C (250°F). The sampling time for each run

shall be at least 60 minutes and the volume shall be at least 4.25 dscm.

(c) The particulate emission rate, E, shall be computed as follows:

$E = V \times C$

where:

(1) E is the particulate emission rate (g/hr),

(2) V is the average volumetric flow rate (dscm/hr) as found from Method 2; and

(3) C is the average concentration (g/dscm) of particulate matter as found from Method 5.

(d) the rate of glass production, P (kg/hr) shall be determined by dividing the weight of glass pulled in kilograms (kg) from the affected facility during the performance test by the number of hours (hr) taken to perform the performance test. The glass pulled in kilograms shall be determined by direct measurement or computed from materials balance by good engineering practice.

(e) The furnace emission rate shall be computed as follows:

$R = E/P$

where:

(1) R is the furnace emission rate (g/kg);

(2) E is the particulate emission rate (g/hr) from (c) above; and

(3) P is the rate of glass production (kg/hr) from (d) above.

[Sec. 114 of Clean Air Act as amended (42 U.S.C. 7414).]

[FR Doc 79-18602 Filed 6-14-79, 8:45 am]

[40 CFR Part 60]

[FRL 1297-3]

Standards of Performance for New Stationary Sources; Glass Manufacturing Plants

AGENCY: Environmental Protection Agency (EPA).

ACTION: Extension of Comment Period.

SUMMARY: The deadline for submittal of comments on the proposed standards of performance for glass manufacturing plants, which were proposed on June 15, 1979 (44 FR 34840), is being extended from August 14, 1979, to September 14, 1979.

DATES: Comments must be received on or before September 14, 1979.

ADDRESSES: Comments should be submitted to Central Docket Section (A-130), United States Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460, Attention: Docket No. OAQPS 79-2.

FOR FURTHER INFORMATION CONTACT: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5271.

SUPPLEMENTARY INFORMATION: On June 15, 1979 (44 FR 34840), the Environmental Protection Agency proposed standards of performance for the control of emissions from glass manufacturing plants. The notice of proposal requested public comments on the standards by August 14, 1979. Due to delay in the shipping of the Background Information Document, sufficient copies of the document have not been available to all interested parties in time to allow their meaningful review and comment by August 14, 1979. EPA has received a request from the industry to extend the comment period by 30 days through September 14, 1979. An extension of this length is justified since the shipping delay has resulted in approximately a three-week delay in processing requests for the document.

Dated: August 8, 1979.

David G. Hawkins,

Assistant Administrator for Air, Noise, and Radiation.

[FR Doc. 79-25233 Filed 8-14-79; 8:45 am]

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

STATIONARY INTERNAL COMBUSTION ENGINES

SUBPART FF

[FRL 1099-5]

[40 CFR Part 60]

Stationary Internal Combustion Engines; Standards of Performance for New Stationary Sources

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The proposed standards, which would apply to facilities that commence construction 30 months after today's date, would limit emissions of nitrogen oxides (NO_x) from new, modified, and reconstructed stationary gas, diesel, and dual-fuel internal combustion (IC) engines to 700 parts per million (ppm), 600 ppm, 600 ppm, respectively at 15 percent oxygen (O_2) on a dry basis. A revision to Reference Method 20 for determining the concentration of nitrogen oxides and oxygen in the exhaust gases from large stationary IC engines is also proposed.

The standards implement the Clean Air Act and are based on the Administrator's determination that stationary IC engines contribute significantly to air pollution. The intent is to require new, modified, and reconstructed stationary IC engines to use the best demonstrated system of continuous emission reduction, considering costs, non-air quality health, and environmental and energy impacts.

A public hearing will be held to provide interested persons an opportunity for oral presentation of data, views, or arguments concerning the proposed standards.

DATES: *Comments.* Comments must be received on or before September 21, 1979.

Public Hearing The public hearing will be held on August 22, 1979 beginning at 9:30 a.m. and ending at 4:30 p.m.

Request to Speak at Hearing. Persons wishing to attend the hearing or present oral testimony should contact EPA by August 15, 1979.

ADDRESSES: *Comments.* Comments should be submitted to Mr. Jack R. Farmer, Chief, Standards Development Branch (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

Public Hearing. The public hearing will be held at the Environmental Research Center Auditorium, Room B101, Research Triangle Park, N.C. 27711. Persons wishing to attend or present oral testimony should notify Mary Jane Clark, Emission Standards and Engineering Divison (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5271.

Standards Support Document. The support document for the proposed standards may be obtained from the EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Standards Support and Environmental Impact Statement: Proposed Standards of Performance for Stationary Internal Combustion Engines," EPA-450/3-78-125a.

Docket. The Docket, number OAQPS-79-5, is available for public inspection and copying at the EPA's Central Docket Section, Room 2903 B, Waterside Mall, Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Proposed Standards

The proposed standards, which are summarized in Table A, would apply to all new, modified, and reconstructed stationary internal combustion engines as follows:

1. Diesel and dual-fuel engines greater than 560 cubic inch displacement per cylinder (CID/cyl).
2. Gas engines greater than 350 cubic inch displacement per cylinder (CID/cyl) or equal to or greater than eight cylinders and greater than 240 cubic inch displacement per cylinder (CID/cyl).
3. Rotary engines greater than 1500 cubic inch displacement per rotor.

The proposed standards, which would go into effect 30 months after the date of proposal (i.e., today's date), would limit the concentration of NO_x in the exhaust gases from stationary gas, diesel and dual-fuel IC engines to 0.0700 percent by volume (700 ppm), 0.600 percent by volume (600 ppm), and 0.0600 percent by volume 600 ppm, respectively, at 15 percent oxygen (O_2) on a dry basis. These emission limits are adjusted upward linearly for IC engines with thermal efficiencies greater than 35 percent.

Table A.—*Summary of Internal Combustion Engine New Source Performance Standard*

Internal combustion engine size and fuel type	NO_x emission limit* (ppm)	Applicability date
Diesel Engines > 560 CID/cyl or > 1500 CID/rotor	600	30 months from date of proposal (i.e., today's date)
Dual-Fuel Engines > 560 CID/cyl or > 1500 CID/rotor	600	30 months from date of proposal (i.e., today's date)
Gas Engines > 350 CID/cyl or ≥ 8 cylinders *and* > 240 CID/cyl or 1500 > CID/rotor	700	30 months from date of proposal (i.e., today's date)

*NO_x emission limit adjusted upward for internal combustion engines with thermal efficiencies greater than 35 percent. Measured NO_x emissions adjusted to standard atmospheric conditions of 101.3 Kilopascals (29.92 inches mercury), 29.4 degrees Centigrade (85 degrees Farhenheit), and 17 grams moisture per kilogram dry aid (75 grains moisture per pound of dry air) in determining compliance with the NO_x emission limit.

The proposed standards would be referenced to standard atmospheric conditions of 101.3 kilopascals (29.92 inches mercury), 29.4 degrees centigrade (85 degrees Fahrenheit), and 17 grams mositure per kilogram dry air (75 grains moisture per pound of dry air). Measured NO_x emission levels, therefore, would be adjusted to standard atmospheric conditions by use of ambient correction factors included in the standard. Manufacturers, owners, or operators may also elect to develop custom ambient condition correction factors, in terms of ambient temperature, and/or humidity, and/or ambient pressure. All correction factors would have to be substantiated with data and approved for use by EPA before they could be used for determining compliance with the proposed standards.

Emergency-standby IC engines and all one- and two-cylinder reciprocating gas engines would be exempt from the NO_x emission standard.

Summary of Environmental and Economic Impacts

The proposed standards would reduce uncontrolled NO_x emissions levels from stationary IC engines by about 40 percent. Based on industry growth projections, a reduction in national NO_x emissions of about 145,000 megagrams per year (160,000 tons per year) would

be realized in the fifth year after the standards go into effect. Except for a few local areas (e.g., Los Angeles), there are currently no state standards liminting NO_x emissions from IC engines.

The proposed standards, however, would increase uncontrolled CO and HC emissions levels from stationary IC engines. Based on industry growth projections, an increase in national CO emissions of about 216,000 megagrams (238,000 tons) annually would be realized in the fifth year after the standards go into effect. Similarly, an increase in national total HC emissions of about 4600 megagrams (5000 tons) annually would be realized in the fifth year after the standards go into effect.

The large increase in CO emissions is due primarily to carbureted or naturally aspirated gas engines. These engines operate closer to stoichiometric conditions under which a small change in the air-to-fuel ratio results in a large increase in CO emissions.

Though total national CO emissions would increase significantly, ambient air CO concentrations in the immediate vicinity of these carbureted or naturally aspirated gas engines would not be adversely affected. As a result of the proposed standards of performance, the CO emissions from a naturally aspirated engine would increase about 160 percent. NO_x emissions from the same engine, however, would decrease concurrently about 40 percent.

Thus, there exists a trade-off between NO_x emissions reduction and CO emissions increase, particularly for carbureted or naturally aspirated gas engines. It should be noted though that CO emissions are considered to be a local problem since CO readily reacts to form CO_2. Additionally, most naturally aspirated gas engines are operated in remote locations where CO is not a problem. NO_x emissions, however, are linked to the formation of photochemical oxidants and are subject to long range transport. Also, NO_x emission control techniques are essentially design modifications, not add-on equipment. therefore, NO_x emissions reductions are much harder to achieve than CO or HC emissions reductions which may be achieved more easily from other sources.

One alternative is to propose a CO emissions limit based on the use of oxidizing catalysts. These catalysts can provide CO and HC emissions reductions on the order of 90 percent. Initial capital costs are high, however, averaging about $7500 for a typical 1000 horsepower naturally aspirated gas engine, or about 15 percent of the purchase price of this engine. EPA feels these costs for control of CO emissions are unreasonable.

The trade-off between NO_x and CO emissions appears reasonable. However, EPA invites comments from state and local air pollution control agencies, environmental groups, the industry, and other interested individuals concerning all aspects of the attractiveness of these standards which reduce NO_x emissions at the expense of CO emissions.

Industry has requested a waiver from the national mobile source standards for diesel engines used in light duty vehicles. Based on their tests, industry believes that the application of NO_x control techniques to these mobile diesel engines causes increased particulate (smoke) emissions. The plumes from most well maintained large-bore stationary IC engines, however, are virtually invisible when the engine is operating at steady state. Though excessive retard will cause diesel and dual fuel units to emit smoke, the NO_x control results used in the development of this standard were only considered if the plume did not exceed ten percent visibility. Therefore, EPA feels the NO_x control techniques used to meet the proposed standards for large stationary IC engines will not cause excessive visible and/or particulate emissions. However, EPA invites comments on the aspects of the proposed standards which reduce NO_x emissions at the expense of visible and/or particulate emissions.

There would be essentially no adverse water pollution, solid waste, or noise impact resulting from the proposed standards.

The energy impact of the proposed standards would be small. Turbocharged gas IC engine fuel consumption would be increased about two percent. Dual-fuel IC engine fuel consumption would be increased about three percent. Diesel IC engine fuel consumption would be increased about seven percent. Naturally aspirated gas IC engine fuel consumption would be increased by about eight percent. The fifth year energy impact of the proposed standards would be equivalent to an increase in fuel oil consumption of about 1.5 million barrels of oil per year (4,300 barrels of oil per day). This represents an increase of only 0.03 percent of the oil projected to be imported in the United States five years after the standards go into effect. In addition, these estimates are based on "worse-case" assumptions which yield the greatest energy impacts, and actual impacts are expected to be lower.

The economic impacts of the proposed standards are considered reasonable. The proposed standards would increase IC engine manufacturers' total capital investment requirements for developmental testing of engine models by about $5 million. These expenditures would be made over a two year period. Analysis of financial reports and other public financial information indicates that the manufacturers' overhead budgets are sufficient to support these requirements without adverse impact on their financial positions. The proposed standards would not give rise to a significant sales advantage for one or two manufacturers over competing manufacturers. The maximum intra-industry sales losses, based on "worst-case" assumptions, would be about six percent.

The proposed standards would increase the total annualized costs to users of a large stationary IC engines of all fuel types by about two to seven percent. The capital cost or purchase price of a large stationary IC engine would increase by about two percent.

The proposed standards would increase the total annualized costs for all engine users by about $32 million in the fifth year after standards go into effect. The total capital investment requirements for all users would equal about 9.6 million on a cumulative basis over the first five years the standards are in effect.

These impacts would result in price increases for the end products or services provided by the industrial and commercial users of large stationary IC engines. The electric utility industry would pass on a price increase after five years of 0.02 percent. After five years, delivered natural gas prices would increase 0.04 percent. Even after a full phase-in period of 30 years, during which new controlled engines would replace all existing uncontrolled engines, the electric utility industry would pass on a price increase of only 0.1 percent. Delivered natural gas prices would increase only 0.3 percent.

Rationale—Selection of Source for Control

Stationary IC engines are sources of NO_x, hydrocarbons (HC), particulates, sulfur dioxide (SO_x), and carbon monoxide (CO) emissions. NO_x emissions from IC engines, however, are of more concern than emissions of these other pollutants for two reasons. First, compared to total U.S. emissions for each pollutant, NO_x is the primary pollutant emitted by stationary engines. Second, EPA has assigned a high priority to development of standards of

performance limiting NO_x emissions. A study by Argonne National Laboratory, "Priorities and Procedures for Development of Standards of Performance for New Stationary Sources of Atmospheric Emissions" (EPA-450/3-76-020), concluded that national NO_x emissions from stationary sources would increase by more than 40 percent between 1975 and 1990 in the absence of additional emission controls. Applying best technology to all sources would reduce this increase but would not prevent it from occurring. This unavoidable increase in NO_x emissions is attributable largely to the fact that current NO_x emission control techniques are based on combustion redesign. In addition, few NO_x emission control techniques can achieve large (i.e., in the range of 90 percent) reductions in NO_x emissions. Consequently, EPA has assigned a high priority to the development of standards of performance for major NO_x emission sources wherever significant reductions in NO_x can be achieved. Studies have shown that IC engines are significant contributors to total U.S. NO_x emissions from stationary sources. Internal combustion engines account for 16.4 percent of all stationary source NO_x emissions, exceeded only by utility and packaged boilers.

Studies have investigated the effect that standards of performance would have on nationwide emissions of particulates, NO_x, SO_x, HC, and CO from stationary sources. The "Priority List for New Source Performance Standards under the Clean Air Act Amendments of 1977," which was proposed in the August 31, 1978, **Federal Register**, ranked sources according to the impact, in tons per year, that standards promulgated in 1980 would have on emissions in 1990. This ranking placed spark ignition IC engines second and compression ignition IC engines third on a list of 32 stationary NO_x emission sources. Consequently, stationary IC engines have been selected for development of standards of performance.

Selection of Pollutants

Nitrogen oxides, hydrocarbons, and carbon monoxide.—Stationary IC engines emit the following pollutants: NO_x, CO, HC, particulates, and SO_x. The primary pollutant emitted by stationary IC engines is NO_x, accounting for over six percent (or 16 percent of all stationary sources) of the total U.S. inventory of NO_x emissions.

Stationary IC engines also emit substantial quantities of CO and HC. Numerous small (1-100 hp) spark ignition engines, which are similar to automotive engines, account for about 20 percent of the uncontrolled HC emissions and about 80 percent of the uncontrolled CO emissions. The large annual production of these small spark ignition engines (approximately 12.7 million), however, makes enforcement of a new source performance standard for this group difficult.

Large-bore engines, which account for three-quarters of NO_x emissions from stationary IC engines, contribute relatively small amounts to nationwide HC and CO emissions, especially if one considers that 80 percent of the HC emissions from large-bore IC engines are methane. An additional factor in considering CO and HC control is that inherent engine characteristics result in a trade-off between NO_x control and control of CO and HC.

As mentioned before, in some cases, particularly naturally aspirated gas engines, the application of NO_x emission control techniques could cause increases in CO and HC emissions. This increase in CO and HC emissions is strictly a function of the engine operating position relative to stoichiometric conditions, not the NO_x control technique. These engines operate closer to stoichiometric conditions under which a small change in the air-to-fuel ratio results in a large increase in CO emissions. Any increase in CO and HC emissions, however, represents an increase in unburned fuel and hence a loss in efficiency. Since IC engines manufacturers compete with one another on the basis of engine operating costs, which is primarily a function of engine operating efficiency, the marketplace will effectively ensure that CO and HC emissions are as low as possible following application of NO_x control techniques.

Though total national CO emissions would increase significantly, ambient air CO concentrations in the immediate vicinity of these carbureted or naturally aspirated gas engines would not be adversely affected. As a result of the proposed standards of performance, the CO emissions from a natually aspirated engine would increase about 160 percent. NO_x emissions from the same engine, however, would decrease concurrently about 40 percent.

Thus, there exists a trade-off between NO_x emissions reduction and CO emissions increase, particularly for carbureted or naturally aspirated gas engines. It should be noted though that CO emissions are considered to be a local problem as CO readily reacts to form CO_2. Additionally, most naturally aspirated gas engines are operated in remote locations where CO is not a problem. NO_x emissions, however, are linked to the formation of photochemical oxidants and are subject to long range transport. NO_x emissions reductions are also much harder to achieve than CO or HC emissions reductions which may be achieved more easily from other sources.

In addition, promulgation of CO standard of performance could, in effect, preclude significant NO_x control. NO_x emissions are primarily a function of combustion flame temperature. Decreasing the air-to-fuel ratio of a gas engine lowers the flame temperature and consequently reduces NO_x formation. As will be discussed later, this technique is the most effective means of reducing NO_x emissions from gas engines. CO emissions, however, are primarily a function of oxygen availability. Decreasing the air-to-fuel ratio reduces oxygen availability and consquently increases CO emissions. Hence naturally aspirated gas engines show a pronounced rise in CO emissions as the air-to-fuel mixture becomes richer (i.e., decreasing air-to-fuel ratio). Thus, placing a limit on CO emissions from internal combustion engines could effectively limit the decrease in the air-to-fuel ratio which would be applied to reduce NO_x emissions from naturally aspirated gas engines and, consequently, could limit the amount of NO_x emissions reduction achievable.

One alternative is to propose a CO emissions limit based on the use of oxidizing catalysts. These catalysts can provide CO and HC emissions reductions on the order of 90 percent. Initial capital costs are high, however, averaging about $7500 for a typical 1000 horsepower naturally aspirated gas engine, or about 15 percent of the purchase price of this engine. EPA feels these costs for control of CO emissions are unreasonable.

The trade-off between NO_x and CO emissions appears reasonable, and consequently, only NO_x emissions from large stationary IC engines were selected for control by standards of performance.

EPA, however, invites comments from state and local air pollution control agencies, environmental groups, the industry, and interested individuals concerning all aspects of the attractiveness of these standards which reduce NO_x emissions at the expense of CO emissions.

Particulate.—Virtually no data are available on particulate emission rates from stationary IC engines. It is believed, however, that particulate emissions from stationary IC engines are

very low because the plumes from most of these engines are not visible. Therefore, neither particulate emissions nor visible emissions (plume opacity) were selected for control by standards of performance.

Sulfur oxides.—Sulfur oxides (SO_x) emissions from an IC engine depend on the sulfur content of the fuel and the fuel consumption of the engine. Scrubbing of IC engine exhausts to control SO_x emissions does not appear to be reasonable from an economic viewpoint. Therefore, the only viable means of controlling SO_x emissions would be combustion of low sulfur fuels. IC engines, however, currently burn low-sulfur fuels and will likely continue to do so because of the lower operating and maintenance costs associated with combustion of these fuels. Therefore, SO_x emissions were not selected for control by standards of performance.

Selection of Affected Facilities

A relatively small number of large-bore IC engines account for over 75 percent of all NO_x emissions from stationary engines. The remaining smaller bore IC engines, which make up the majority of all engine sales, are, from a NO_x emission standpoint, a considerably less significant segment of the industry. These engines have different emission characteristics due to their size, design, and operating parameters. The NO_x reduction technology developed for use on the large-bore IC engines may not be directly applicable to these smaller engines. Therefore, at this time, only large-bore engines have been selected for control by standards of performance.

Diesel engines.—The primary high usage (large emissions impact) domestic application of large-bore diesel engines during the past five years has been for oil and gas exploration and production. The market for prime (continuous) electric generation and other industrial applications all but disappeared after the 1973 oil embargo, but was quickly replaced by sales of standby electric units for building services, utilities, and nuclear power stations. The rapid growth in the oil and gas production market occurred because diesel units are being used on oil drilling rigs of various sizes. Sales of engines to export applications have also grown steadily since 1972, and are now a major segment of the entire sales market.

Medium-bore as well as large-bore engines are sold for oil and gas exploration, standby service, and other industrial applications. Applying standards of performance to medium-bore engines serving the same applications as large-bore designs would increase the number of affected facilities from about 200 to about 2,000 units per year (based on 1976 sales information) but consequently further reduce national NO_x emissions. Medium-bore sales accounted for significant NO_x emissions in 1976 (approximately 12,500 megagrams). It is estimated that approximately 25 percent, or about 500 of these units in high usage applications, accounted for most of the medium/bore NO_x emissions, since most of the remainder of these units were sold as standby generator sets. Though the potential achievable NO_x reduction is significant, this alternative causes the standard to apply to lower power engine models with fewer numbers of cylinders competing with other unregulated engines in different stationary markets. Additionally, considering this large number, and the remoteness and mobility of petroleum applications, this alternative would create serious enforcement difficulties. Consequently, a definition is required that distinguishes large-bore engines competing with medium-bore high power engines used for baseload electrical generation from large-bore engines competing solely with other large-bore engines.

One approach would be to define diesel engines covered by standards of performance as those exceeding 560 cubic inch displacement per cylinder (ie., CID/cyl). IC engines below this size are generally used for different applications than those above it. Considering the sizes and displacements offered by each diesel manufacturer and the applications served by diesel engines, this definition was selected as a reasonable approach for separating large-bore engines that compete with medium-bore engines from large-bore engines that compete solely with each other.

Dual-fuel engines.—The concept of dual-fuel operation was developed to take advantage of both compression ignition performance and inexpensive natural gas. These engines have been used almost exclusively for prime electric power generation. Shortages of natural gas and the 1973 oil embargo have combined to significantly reduce the sales of these engines in recent years. The few large-bore units that were sold (11 in 1976) were all greater than 350 CID/cyl.

Although a greater-than-350-CID/cyl limit would subject nearly all new dual-fuel sources to standards of performance, the criterion chosen to define affected diesel engines (i.e., greater than 560 CID/cyl) has also been selected for dual-fuel engines. The primary reason is that supplies of natural gas are likely to become even more scarce; thus dual-fuel engines will likely operate as diesel engines.

Gas engines.—The primary application of large-bore gas engines during the past five years has been for oil and gas production. The primary uses are to power gas compressors for recovery, gathering, and distribution. About 75 to 80 percent of all gas engine horsepower sold during the past five years was used for these applications. During this time, sales to pipeline transmission applications declined. Pipeline applications combined with standby power, electric generation, and other services (industrial and sewage pumping) accounted for the remaining 20 to 25 percent of horsepower sales. The growth of oil and gas production applications during this period corresponds to the increasing efforts to find new, or to recover marginal, gas reserves and distribute them to the existing pipeline transmission network.

It is estimated that the 400,000 horsepower of large-bore gas engine capacity sold for oil and gas production applications in 1976 emitted 35,000 megagrams of NO_x emissions, or nearly three times more NO_x than was emitted by the 200,000 horsepower of large-bore diesel engine capacity sold for the same application in that year. Thus, large-bore gas engines are primary contributors of NO_x emissions from new stationary IC engines, and standards of performance should be directed particularly at these sources.

If affected engines were defined as those greater than 350 CID/cyl, then all competing manufacturers of large-bore gas engines except one would be affected by the proposed standards of performance. This one manufacturer produces primarily medium-bore engines. Therefore, a 350 CID/cyl limit would give this one manufacturer an unfair competitive advantage over other large-bore engine manufacturers. Consequently, this definition should be lowered, or another definition adopted, to include the manufacturer in question. Either of the following two definitions would subject this manufacturer's gas engine to standards of performance:

- Greater than 240 CID/cyl
- Greater than 350 CID/cyl or greater than or equal to 8-cylinder and greater than 240 CID/cyl

Both measures would essentially include only this manufacturer's gas engines which compete with other manufacturer's large-bore gas engines. The second definition has a slight

advantage over the first since it includes only gas engines produced by all manufacturers that have competitor counterparts of about the same power. Therefore, this second definition of affected gas engines was selected.

Rotary engines.—Rotary or wankel type engines have only recently been introduced as power sources in package stationary applications. These internal combustion engines convert energy in the fuel directly to rotary motion rather than through reciprocating pistons and a crankshaft. These engines consist of a triangular rotor rotating eccentrically inside an epitrochoidal housing.

Until recently the largest rotary engine in production was 90 cubic inches per rotor. Now, however, one manufacturer is producing a rotary engine with a displacement of 2,500 cubic inches per rotor. This engine is being offered as a one rotor model rated at 550 horsepower and a two rotor unit rated at 1,100 horsepower.

The displacement of the rotary engine is defined as the volume contained in the chamber, bordered by one flank of the rotor and the housing, at the instant the inlet port closes. These engines are presently sold as naturally aspirated gaseous fueled units primarily for fuel gathering compressors and power generation on offshore platforms.

NO_x emissions from these large rotary engines are similar to NO_x emissions from naturally aspirated four stroke, gaseous fuel reciprocating engines. Further sales of these engines are estimated to be 50,000 horsepower per year over the next five years. Since these large rotary engines contribute to NO_x emissions, standards of performance for new stationary IC engines should include these sources.

Due to design differences, rotary engines develop more power per cubic inch displacement than reciprocating engines. If the lower cutoff limit for affected rotary engines were 350 CID/rotor—in an attempt to equate displacement per cylinder and also use the same limit as for gaseous fueled engines—then rotary engines of approximately 100 horsepower would be regulated by standards of performance. Thus rotary engine manufacturers would be at a competitive disadvantage with unregulated reciprocating engine manufacturers in this power range. To ensure that the standards of performance do not alter the competitive position of the two types of engines, the lower size limit for affected rotary engines should correspond to an engine whose power output is the same as the smallest affected reciprocating unit.

Based on this criterion of equivalent horsepower, it is estimated that rotary engines greater than 1,500 CID/rotor would compete with reciprocating engines greater than 350 CID/cyc. Therefore, a greater than 1,500 CID/rotor definition of affected rotary engines is selected to subject these engines to standards of performance. The definition applies to rotary engines of all fuel types.

Exemptions.—One and two cylinder reciprocating engines could be covered by the above definitions. These engines, however, account for less than 10 percent of all engine horsepower and therefore are less significant NO_x emitters. Additionally, the engines operate at a small fraction of their power output and probably have lower NO_x emissions than the larger, high rated engines. Therefore, all one and two cylinder reciprocating engines were exempted from standards of performance.

Emergency standby engines also require special consideration. These engines operate less than 200 hours per year under all but very unusual circumstances. Consequently, they add relatively little to regional or national total NO_x emissions. The largest category of emergency standby units is for nuclear power plants, where these engines provide power for the pumps used for cooling the reactors. These engines must attain a set speed in ten seconds and must assume full rated load in 30 seconds. In some cases, application of the demonstrated NO_x control technique limits the responsiveness of these engines in emergency situations. Therefore, all emergency standby engines are exempted from standards of performance.

Selection of Best System of Emission Reduction

Four emission control techniques, or combinations of these techniques, have been identified as demonstrated NO_x emission reduction systems for stationary large-bore IC engines. These techniques are: (1) Retarded ignition or fuel injection, (2) air-to-fuel ratio changes, (3) manifold air cooling, and (4) derating power output (at constant speed). In general, all four techniques are applied by changing an engine operating adjustment.

Fuel injection retard is the most effective NO_x control technique for diesel engines. Similarly, air-to-fuel ratio change is the most effective NO_x control technique for gas engines. Both retard and air-to-fuel ratio changes are effective in reducing NO_x emissions from dual-fuel engines.

Other NO_x emission control techniques exist but are not considered feasible alternatives. Of these other techniques, catalytic reduction of NO_x emissions through the use of systems similar to automobile catalyst systems is probably the first to come to mind. Most large stationary IC engines operate at air-to-fuel ratios that are typically much greater than stoichiometric, and consequently the engine exhaust is characterized by high oxygen (O_2) concentrations. Existing automobile catalytic converters, however, operate near stoichiometric conditions (i.e., low exhaust O_2 concentrations). These automobile catalysts are not effective in reducing NO_x in the presence of high O_2 concentrations.

Consequently, entirely different catalyst systems would be needed to reduce NO_x emissions from large stationary IC engines. Although such catalyst systems are currently under development and have been demonstrated for one very narrow application (i.e., fuel-rich naturally aspirated gas engines), they have not been demonstrated for the broad range of IC engines manufactured, such as turbocharged engines, fuel-lean gas engines, or diesel engines. For these engines the reduction of NO_x by ammonia injection over a precious metal (e.g., platinum) catalyst appears promising with NO_x reductions of approximately 90 percent having been reported; however, the cost of such a system is high.

For a typical 1000 horsepower engine approximately two cubic feet of honeycomb catalyst (platinum based) would be required to ensure proper operation of the system. The cost of the catalyst was estimated at $1,500/cubic foot (in 1973). Assuming that the engine costs $150/hp and that the cost of the catalyst accounts for about one-half the cost of the whole system (container, substrate, and catalyst), the capital investment for this control system represents approximately four percent of the engine purchase price.

The amount of ammonia required for an ammonia/catalyst NO_x reduction system will depend on the NO_x emission rate (g/hp-hr). Based on uncontrolled NO_x emission rates of 9 to 22 g/hp-hr, and the cost of $150/ton for the ammonia, the cost impact of injecting ammonia is approximately 5 to 15 percent of the total annual operating costs ($/hp-hr) for natural gas engines. When this operating cost is combined with the capital cost of the catalytic system discussed above, the total cost

increase is about 25 percent. Therefore, in continuous service applications this system is expensive compared to control techniques such as retard or air-to-fuel changes.

It is also important to note that the consumption of ammonia can be expressed as a quantity of fuel since natural gas is generally used to produce ammonia. Assuming a conservative NO_x emission rate of 20 g/hp-hr, and engine heat rate of 7500 Btu/hp-hr, a heating value of 21,800 Btu/lb for natural gas, and a requirement for approximately 900 lbs of gas per ton of ammonia produced, then the ammonia necessary for the catalytic reduction has the same effect on the supply of natural gas as a two percent increase in fuel consumption. Additional fuel is required to operate the plant which produces the ammonia.

Catalytic reduction, therefore, is currently not a demonstrated NO_x emission control technique which could be used by all IC engines. Consequently, although catalytic reduction of NO_x emissions could be used in a few isolated cases to comply with standards of performance, it could not be used as the basis for developing standards of performance which are applicable to all IC engines.

The data and information presented in the Standards Support and Environmental Impact Statement clearly indicate that the four demonstrated control techniques mentioned above will reduce NO_x emissions from IC engines. Due to inherent differences in the uncontrolled emission characteristics of various engines, it is difficult to draw conclusions from this data and information concerning the ability of these emission control techniques to reduce NO_x emissions from all IC engines to a specific level. In general, engines with high uncontrolled NO_x emissions levels have relatively high controlled NO_x emissions levels and engines with low uncontrolled NO_x emissions levels have relatively low contolled NO_x emissions levels. To eliminate these inherent differences in NO_x emission characteristics among various engines, the data were analyzed in terms of the degree of reduction in NO_x emissions as a function of the degree of application of each emission control technique.

Ignition retard in excess of eight degrees in diesel engines frequently leads to unacceptably high exhaust temperatures, resulting in exhaust value and/or turbocharger turbine damage. Similarly, changes in the air-to-fuel ratio in excess of five percent in gas engines frequently lead to excessive misfiring or detonation which could lead to a serious explosion in the exhaust manifold. Eight degrees of ignition retard in diesel engines and five percent change in air-to-fuel ratios in gas engines yield about a 40 percent reduction in NO_x emissions. Consequently, in light of these limitations to the application of these emission control techniques, it is apparent that a 40 percent reduction in NO_x emissions is the most stringent regulatory option which could be selected as the basis for standards of performance. An alternative of 20 percent NO_x emission reduction was also considered a viable regulatory option which could serve as the basis for standards of performance.

Environmental impacts.—Standards of performance based on alternative I (20 percent reduction) would reduce national NO_x emissions by 72,500 megagrams annually in the fifth year after the standards went into effect. In contrast, standards of performance based on alternative II (40 percent reduction) would reduce national NO_x emissions by about 145,000 megagrams annually in the fifth year after the standards went into effect. Thus, standards of performance based on alternative II would have a much greater impact on national NO_x emissions than standards based on alternative I.

Standards of performance based on either alternative would, with the exception of naturally aspirated gas engines, result in a small increase in carbon monoxide (CO) and hydrocarbon emissions (HC) from most engines. A typical diesel engine with a sales-weighted average uncontrolled CO emission level of approximately 2.9 g/hp-hr would experience an increase in CO emissions of about 0.75 g/hp-hr to comply with standards of performance based on alternative I, and an increase of about 1.5 g/hp-hr to comply with standards of performance based on alternative II. Total hydrocarbon emissions would increase a sales-weighted average uncontrolled emission level of 0.3 g/hp-hr by about 0.06 g/hp-hr to comply with standards based on alternative I, and would increase by about 0.1 g/hp-hr to comply with standards of performance based on alternative II.

Similarly, a typical dual-fuel engine with a sales-weighted average uncontrolled CO emission level of approximately 2.7 g/hp-hr would experience an increase in CO emissions of about 1.2. g/hp-hr and about 2.7 g/hp-hr to comply with standards of performance based on alternatives I and II, respectively. Total HC emissions, however, would increase by about 0.3 g/hp-hr from a sales-weighted average uncontrolled level of approximately 2.8 g/hp-hr to comply with standards of performance based on alternative I. To comply with standards of performance based on alternative II total hydrocarbon emissions would decrease by 0.6 g/hp-hr.

A typical turbocharged or blower scavenged gas engine with a sales-weighted average uncontolled CO emission level of approximately 7.7 g/hp-hr would experience an increase in CO emissions of about 1.9 g/hp-hr to comply with standards of performance based on alternative I and about 3.8 g/hp-hr to comply with standards of performance based on alternative II. Total hydrocarbon emissions would increase a sales-weighted average uncontrolled level of approximately 1.9 g/hp-hr by about 0.2 g/hp-hr to comply with standards of performance based on alternative I. To comply with standards of performance based on alternative II total hydrocarbon emissions would increase by about 0.4 g/hp-hr.

A typical naturally aspirated gas engine with a sales-weighted average uncontrolled CO emission level of approximately 7.7 g/hp-hr would experience an increase in CO emissions of about 3.9 g/hp-hr to comply with standards of performance based on alternative I and about 17 g/hp-hr to comply with standards of perfomance based on alternative II. Total hydrocarbon emissions would increase a sales-weighted average uncontrolled level of approximately 1.8 g/hp-hr by about 0.04 g/hp-hr to comply with standards of performance based on alternative I. To comply with standards of performance based on alternative II total hydrocarbon emissions would increase by about 0.08 g/hp-hr

As noted earlier, the increase in ambient air CO levels resulting from compliance with NO_x standards of performance based on either alternative would be insignificant compared to the NAAQS of 10 mg/m^3 for CO. Additionally, CO emissions are a local problem as CO readily reacts to form CO_2. Additionally, most naturally aspirated engines are operated in remote or sparcely populated areas, CO emissions will not present a problem.

Currently, national stationary CO emissions are approximately 33 million megagrams per year. Standards of performance based on alternative I would increase these emissions by approximately 63,000 megagrams annually in the fifth year after the standards went into effect. In contrast, standards of performance based on alternative II would increase national CO emissions by about 216,000

megagrams annually in the fifth year after the standards went into effect.

Standards of performance based on alternative I would increase national total HC emissions by about 2,300 megagrams annually in the fifth year after the standards went into effect compared to an increase of about 4,600 megagrams annually associated with alternative II. It is estimated that more than 90 percent of total HC emissions from large-bore gas-fuel engines and 75 percent of total HC emissions from large-bore dual-fuel engines are methane, which is nonreactive and does not lead to oxidant formation. Standards of performance based on alternative I would increase national reactive HC emissions by approximately 108 megagrams annually in the fifth year after the standards went into effect, compared to an increase of approximately 216 megagrams annually associated with alternative II.

Stationary IC engines are sources of NO_x, HC, and CO emissions, with both NO_x and HC contributing to oxidant formation. With regard to regulation of emissions from IC engines, NO_x emissions are of more concern than emissions of HC for two reasons. First, NO_x is emitted in greater quantities from stationary IC engines than HC. Second, as mentioned earlier, a high priority has been assigned to development of standards of perfomance limiting NO_x emissions. A study by Argonne National Laboratory, "Priorities and Procedures for development of Standards of Perfomance for New Stationary Sources of Atmospheric Emissions," concluded that national NO_x emissions from stationary sources would increase by more than 40 percent between 1975 and 1990 in the absence of additional emission controls. The slight increase in HC emissions from IC engines associated with control of NO_x can be offset in most cases from other sources more easily than NO_x emissions can be reduced from other sources. Therefore, the adverse enviromental impact of increased HC emissions because of the reduction in NO_x emissions is considered small.

There would be essentially no water pollution, solid waste, or noise impact of standards of performance based on either alternative I or alternative II.

Thus, as reflected in Table 1, the environmental impacts of standards of performance based on either alternative are small and reasonable

TABLE I

ENVIRONMENTAL IMPACTS OF ALTERNATIVES

Pollutant	Base Level[a]	Alternative I	Alternative II
National NO_x Emissions	14.6 x 10^6 megagrams	Reduced by 72,500 megagrams annually in the fifth year after standard goes into effect	Reduced by 145,000 megagrams annually in the fifth year after standard goes into effect
National CO Emissions	33.0 x 10^6 megagrams	Increased by 63,000 megagrams annually in the fifth after standard goes into effect	Increased by 216,000 megagrams annually in the fifth after standard goes into effect
National Total HC Emissions	10.2 x 10^6 megagrams	Total Hydrocarbons Increased by 2,300 megagrams annually in the fifth year after standard goes into effect Reactive Hydrocarbons Increased by 108 megagrams annually in the fifth year after standard goes into effect	Total Hydrocarbons Increased by 4,600 megagrams annually in the fifth year after standard goes into effect Reactive Hydrocarbons Increased by 216 megagrams annually in the fifth year after standard goes into effect
Water Pollution	--	No increase	No increase
Solid Waste	--	No increase	No increase
Noise	--	No adverse impact	No adverse impact

aTotal U.S. emission from stationary sources as per EPA Nationwide Air Pollutant Inventory for 1975

Energy impacts. The potential energy impact of standards of performance based on either alternative is small. Standards of performance based on alternative I would increase the fuel consumption of a typical blower-scavenged or turbocharged gas engine by approximately one percent, whereas standards of performance based on alternative II would increase the fuel consumption by approximately two percent.

Standards of performance based on alternative I would increase the fuel consumption of a typical dual-fuel engine by about one percent. Standards of performance based on alternative II, however, would increase the fuel consumption by three percent. Standards of performance based on alternative I would increase the fuel consumption of a typical naturally aspirated gas engine by approximately six percent. Standards of performance based on alternative II, however, would increase the fuel consumption by approximately eight percent.

Standards of performance based on alternative I would increase the fuel consumption of a typical diesel engine by approximately three percent. Standards of performance based on alternative II, however, would increase the fuel consumption by approximately seven percent.

The potential energy impact in the fifth year after the standards go into effect, based on alternative I, would be equivalent to an increase in fuel consumption of approximately 1.03 million barrels of oil per year compared to the uncontrolled fuel consumption of IC engines affected by the standards of 31 million barrels per year. The potential energy impact in the fifth year after the standard goes into effect, based on alternative II, would be equivalent to approximately 1.5 million barrels of oil per year.

It should be noted that the largest increase represents only 0.02 percent of the 1977 domestic consumption of crude oil and natural gas. The largest increase also represents only 0.03 percent of the projected total oil imported to the U.S. five years after the standards go into effect.

Thus, the energy impacts of standard of performance based on either alternative are small and reasonable.

Economic impact of alternatives. Manufacturers of stationary IC engines would incur additional costs due to standards of performance. These costs, however, would be small. It is estimated that the total cost to the manufacturers for each engine model family, including development, durability tests, and retooling, would be approximately: (1) $125,000 for retard and air-to-fuel change; (2) $150,000 for manifold air temperature reduction; and (3) $25,000 for derate. For each manufacturer therefor, total costs would vary depending on (1) the number of engine model families produced; (2) their degree of advancement in emission testing; (3) the uncontrolled emission levels of their engines; (4) the development and durability testing required to produce engines that can meet proposed standards of performance; and (5) the emission control technique selected for NO_x emission reduction.

The manufacturer's total capital investment requirements for developmental testing of engine models is estimated to be about $4.5 million to comply with standards of performance based on alternative I and about $5 million to comply with standards of performance based on alternative II. These expenditures would be made over a two year period. Analyses of the financial statements and other public financial information of engine manufacturers or their parent companies indicate that the manufacturer's overhead budgets are sufficient to support the development of these controls without adverse impact on their financial position.

Manufacturers would not experience significant differential cost impacts among competing engine model families. Consequently, no significant sales advantages or disadvantages would develop among competing manufacturers as a result of standards of performance based on either alternative. Based on "worst-case" assumptions, the maximum intra-industry sales losses would be about six percent as a result of standards of performance based on either alternative. Thus, the intra-industry impacts would be moderate and not cause any major dislocations within the industry.

The total annualized cost penalities imposed on IC engines by standards of performace would also have very little impact with regard to increasing sales of gas turbines. Standards of performance based on alternative I would result in no loss of sales to gas turbines whereas standards of performance based on alternative II could result in the possible loss of sales for one diesel manufacturer.

It should be noted that this conslusion is based on limited data. It is quite likely, however, that this manufacturer's line of diesel engines, through minor combustion modifications, could reduce its NO_x emissions as discussed in the SSEIS to levels comparable to those of other manufacturers. Further, due to technical limitations, economic considerations, and customer preference, it is unlikely that IC engine users would switch to gas turbines. Thus, the impact on sales would be minimal.

Therefore, the economic impacts on the manufacturers of standards of performance based on either alternative are considered small and reasonable.

The application of NO_x controls will also increase costs to the engine user. The magnitude of this increase will depend upon the amount and type of emission control applied. Fuel penalties are the major factor affecting this increase.

The following four end uses represent the major applications of diesel, dual-fuel, and natural gas engines: (1) Diesel engine, electrical generation; (2) dual-fuel engine, electrical generation; (3) gas engine, oil and gas transmission and (4) gas engine, oil and gas production.

The manufacturers' capital budget requirements to develop and test engine NO_x control techniques would be regarded as an added expense and most likely passed on to the engine users in the form of higher prices. Therefore, users of IC engines would have to expend additional capital to purchase more expensive engines. This capital cost penalty, however, is small. A two percent increase in engine price would be expected on the average as the result of standards of performance based on either alternative. Typical initial costs for uncontrolled diesel and dual-fuel, electrical generation engines, and natural gas oil and gas transmission engines are about $150/hp. Initial costs for gas, gas production engines are about $50/hp.

The total additional capital cost for all users would equal about $9.6 million on a cumulative basis over the first five years to comply with standards of performance based on either alternative.

As mentioned earlier, fuel penalties are the major factor affecting the total annualized cost of high usage engines. The total annualized cost of a typical uncontrolled diesel, electrical generation engine is about 2.5¢/hp-hr. As a result of standards of performance based on alternative I this total annualized cost would increase by about 0.04¢/hp-hr (1.5 percent). As a result of standards of performance based on alternative II this total annualized cost would increse by about 0.11¢/hp-hr (4.5 percent).

The total annualized cost of a typical uncontrolled dual-fuel electrical generation engine is about 2.8¢/hp-hr. As a result of standards of performance

base on alternative II this total annualized cost would increase by about 0.07¢/hp-hr (2.5 percent). As a result of standards of performance based on alternative Ii this total annualized cost would increase by about 0.09¢/hp-hr (3.2 percent).

The total annualized cost of a typical uncontrolled gas, oil and gas transmission engine is about 2.2¢/hp-hr. As a result of standards of performance based on alternative I this total annualized cost would increase by about 0.02¢/hp-hr (1 percent). As a result of standards of performance based on alternative II this total annualized cost would increase by about 0.04¢/hp-hr (2 percent).

The total annualized cost of a typical uncontrolled gas, oil and gas production engine is about 2.2¢/hp-hr. As a result of standards of performance based on alternative I this total annualized cost would increase by about 0.14¢/hp-hr (6.5 percent). As a result of standards of performance based on alternative II this total annualized cost would increase by about 0.16¢/hp-hr (7.5 percent).

Thus, the total annualized cost penalties to the user associated with either alternative are small. Total uncontrolled annualized costs of about $580 million by all large stationary IC engine users would increase by about $25 million to comply with standards of performance based on alternative I and would increase by about $32 million to comply with standards of performance based on alternative II in the fifth year after the standards go into effect.

The economic impacts on users arising from the cost penalties outlined above would be small. In general, these impacts translate into price increases for the end products or services provided by the industrial and commercial users of large stationary IC engines. The electric utility industry would pass on a price increase after five years of 0.02 percent to comply with standards of performance based on either alternative. After five years, delivered natural gas prices would increase 0.02 percent if standards of performance based on alternative I were applied and 0.04 percent if standards of performance based on alternative II were applied.

Even after a full phase-in period of 30 years, during which new controlled engines would replace all existing uncontrolled engines, the electric utility industry would realize a price increase of only 0.1 percent to comply with standards of performance based on either alternative. Similarly, delivered natural gas prices would increase only 0.1 percent if standards of performance based on alternative I were applied and 0.3 percent if standards of performance based on alternative II were applied. Thus, as summarized in Table II, the economic impacts of standards of performance based on either alternative are considered small and reasonable.

TABLE II

ECONOMIC IMPACTS OF ALTERNATIVES

Impact	Uncontrolled Level of Cost	Alternative I	Alternative II
Impact on Manufacturer			
Capital budget requirements	--	$4.5 million over two years; able to generate internally from profits.	$5 million over two years; able to generate internally from profits.
Intra-industry competition	--	Maximum sales loss unlikely to exceed 6% of internal combustion engine sales for any firm.	6% maximum loss for any firm
Competition from gas turbines	--	No losses.	Possible sales loss for one diesel manufacturer.
Impact on End-Use Applications			
Total annualized cost[a]			
Diesel fuel, electrical generation	2.5¢/hp-hr	Base increased by 0.04¢/hp-hr	Increased by 0.11¢/hp-hr
Dual-fuel, electrical generation	2.8¢/hp-hr	Increased by 0.07¢/hp-hr	Increased by 0.09¢/hp-hr
Natural gas fuel, oil and gas transmission	2.2¢/hp-hr	Increased by 0.02¢/hp-hr	Increased by 0.04¢/hp-hr
Natural gas fuel, oil and gas production	2.2¢/hp-hr	Increased by 0.14¢/hp-hr	Increased by 0.16¢/hp-hr
Totals of all new engines after 5 years	$580 million	Increased by $25 million	Increased by $32 million
Capital Cost Penalty[a]			
Diesel fuel, electrical generation or dual fuel, electrical generation or natural gas fuel, oil and gas transmission	$150/hp	Increased by $3.00/hp	Increased by $3.00/hp
Natural gas fuel, oil and gas production	$ 50/hp	Increased by $1.00/hp	Increased by $1.00/hp
Totals etc.	$450 million	$9 6 million on a cumulative basis over first 5 years after standards go into effect.	$9.6 million on a cumulative basis over first 5 years after standards go into effect.
Impact on Product Prices and Users			
Electricity prices	--	U.S. electric bill up 0.02% after 5 years. U.S. electric bill up 0.1% after full phase-in.	U S. electric bill up 0 02% after 5 years. U.S electric bill up 0.1% after full phase-in[b].
Gas prices	--	Delivered natural gas prices up 0.02% after 5 years. Delivered natural gas prices up 0.1% after full phasein.	Delivered natural gas prices up 0.04% after 5 years Delivered natural gas prices up 0 3% full phasein.

Assumed typical 2000 horsepower engine operating 8000 hours per year in all cases

Full phase-in implies replacement of all existing engines

Based on the assessment of the impacts of each alternative, and since alternative II achieves a greater degree of NO_x reduction, it is selected as the best technological system of continuous emission reduction of NO_x from stationary large-bore IC engines, considering the cost of achieving such emission reduction, any nonair quality health and environmental impact, and energy requirements.

Selection of Format for the Proposed Standards

A number of different formats could be used to limit NO_x emissions from large stationary IC engines. Standards could be developed to limit emissions in terms of: (1) Percent reduction; (2) mass emissions per unit of energy (power) output; or (3) concentration of emissions in the exhaust gases discharged to the atmosphere.

Analysis of the effectiveness of the various NO_x emission control techniques clearly shows that the ability to achieve a percent reduction in NO_x emissions is what has been demonstrated. However, a percent reduction format is highly impractical for two reasons. First, a reference uncontrolled NO_x emission level would have to be established for each manufacture's engine, a difficult task since some manufacturers produce as many as 25 models which are sold with several ratings. Second, a reference uncontrolled NO_x emission level would have to be established for any new engines developed after promulgation of the standard. This would be quite simple for engines that employed NO_x control techniques such as ignition retard or air-to-fuel ratio change to comply with standards of performance. Emissions could be measured without the use of these techniques. For engines designed to comply with the standards through the use of combustion chamber modifications, however, this would not be possible. Thus, new engines would receive no credit for the NO_x emission reduction achieved by combustion chamber redesign and this would effectively preclude the use of this approach to comply with the standards.

A mass-per-unit-of-energy-output format, typically referred to as brake-specific emissions (g/hp-hr), relates the total mass of NO_x emissions to the engine's productivity. Although brake-specific mass standards (g/hp-hr) appear meaningful becasue they relate directly to the quantity of emissions discharged into the atmosphere, there are disadvantages in that enforcement of mass standards would be costly and complicated in practice. Exhaust flow and power output would have to be determined in addition to NO_x concentration. Power output can be determined from an engine dynamometer in the laboratory, but dynamometers cannot be used in the field. Power output could be determined by: (1) Inferring the power from engine operating parameters (fuel flow, rpm, manifold pressure, etc.); or (2) inferring engine power from the output of the generator or compressor attached to the engine. In practice, however, these approaches are time consuming and are less accurate than dynamometer measurements.

Another possible format would be to limit the concentration of NO_x emissions in the exhaust gases discharged to the atmosphere. Concentrations would be specified in terms of parts-per-million volume (ppm) of NO_x. The major advantage of this format is its simplicity of enforcement. As compared to the formats discussed previously, only a minimum of data and calculations are required, which decreases testing costs and minimizes errors in determining compliance with an emission standard since measurements are direct.

The primary disadvantages associated with concentration standards are: (1) A standard could be circumvented by dilution of exhaust gases discharged into the atmosphere, which lowers the concentration of pollutant emissions but does not reduce the total pollutant mass emitted; and (2) a concentration standard could penalize high efficiency engines. Both these problems, however, can be overcome through the use of appropriate "correction" factors.

Since the percent reduction format is impractical, and the problems associated with the enforcement of mass standards (mass-per-unit energy output) appear to outweigh the benefits, the concentration format was selected for standards of performance for large stationary IC engines.

As mentioned above, because a concentration standard can be circumvented by dilution of the exhaust gases, measured concentrations must be expressed relative to some fixed dilution level. For combustion processes, this can be accomplished by correcting measured concentrations to a reference concentration of O_2. The O_2 concentration in the exhaust gases is related to the excess (or dilution) air. Typical O_2 concentrations in large-bore IC engines can range from 8 to 16 percent but are normally about 15 percent. Thus, referencing the standard to a typical level of 15 percent O_2 would prevent circumvention by dilution.

As also mentioned above, selection of a concentration format could penalize high efficiency IC engines. These highly efficient engines generally operate at higher temperature and pressures and, as a result, discharge gases with higher NO_x concentrations than less efficient engines, although the brake-specific mass emissions from both engines could be the same. Thus, a concentration standard based on low efficiency engines could effectively require more stringent controls for high efficiency engines. Conversely, a concentration standard based on high efficiency engines could allow such high NO_x concentrations that less efficient engines would require no controls. Consequently, selecting a concentration format for standards of performance requires an efficiency adjustment factor to permit higher NO_x emissions from more efficient engines.

The incentive for manufacturers to increase engine efficiency is to lower engine fuel consumption. Therefore, the objective of an efficiency adjustment factor should be to give an emissions credit for the lower fuel consumption of more efficient IC engines. Since the fuel consumption of IC engines varies linearly with efficiency, a linear adjustment factor is selected to permit increased NO_x emissions from highly efficient IC engines.

The efficiency adjustment factor needs to be referenced to a baseline efficiency. Most large existing stationary IC engines fall in the range of 30 to 40 percent efficiency. Therefore, 35 percent is selected as the baseline efficiency.

The efficiency adjustment factor included in the proposed standards permits a linear increase in NO_x emissions for engine efficiencies above 35 percent. This adjustment would not be used to adjust the emission limit downward for IC engines with efficiencies of less than 35 percent. This efficiency adjustment factor also applies only to the IC engine itself and not the entire system of which the engine may be a part. Since Section 111 of the Clean Air Act requires the use of the best system of emission reduction in all cases, this precludes the application of the efficiency adjustment factor to an entire system. For example, IC engines with waste heat recovery may have a higher overall efficiency than the IC engine alone. Thus, the application of the efficiency adjustment factor to the entire system would permit greater NO_x emissions because of the system's higher overall efficiency, and would not necessarily require the use of the best demonstrated system emission reduction on the IC engine.

Selection of Numerical Emission Limits

Overall approach.—As mentioned earlier it is difficult to select a specific NO_x emission limit which all IC engines could meet primarily through the use of ignition retard or air-to-fuel ratio change. Because of inherent differences among various IC engines with regard to uncontrolled NO_x emission levels, there exists a rather large variation within the data and information included in the Standards Support and Environmental Impact Statement concerning controlled NO_x emission levels. Generally speaking, engines with relatively low uncontrolled NO_x emissions levels achieved low controlled NO_x emissions levels and engines with high uncontrolled NO_x emissions levels achieved relatively high controlled NO_x emissions levels. Consequently, the following alternatives were considered for selecting the numerical concentration emission limits based on a 40 percent reduction in NO_x emissions:

1. Apply the 40 percent reduction to the highest observed uncontrolled NO_x emission level.

2. Apply the 40 percent reduction to a sales-weighted average uncontrolled NO_x emission level.

3 Apply the 40 percent reduction to this sales-weighted average uncontrolled NO_x emission level plus one standard deviation.

The highest observed uncontrolled NO_x emission levels for gas, dual-fuel and diesel engines are as follows: (1) Gas, 29 g/hp-hr (2) dual-fuel, 15 g/hp-hr, and (3) diesel, 19 g/hp-hr.

Sales-weighted uncontrolled NO_x emission levels were determined by applying a sales weighting to each manufacturer's average uncontrolled NO_x emissions for engines of each fuel type The sales weighting, based on horsepower sold gives more weight to those engine models which have the highest sales The sales-weighted average uncontrolled NO_x emission level for each engine fuel type are as follow: (1) Gas 15 g/hp-hr. (2) dual-fuel, 8 g/hp-hr and (3) diesel, 11 g/hp-hr.

The third alternative incorporates a "margin for engine variability" by adding one standard deviation to the sales-weighted average uncontrolled NO_x emission level and then applying the 40 percent reduction. Standard deviations were calculated from the uncontrolled NO_x emission data included in the Standards Support and Environmental Impact Statement, assuming the data had normal distribution. A subsequent statistical evaluation of the data indicated that this assumption was valid: The standard deviations for each engine fuel type are as follows: (1) Gas, 4 g/hp-hr. (2) dual-fuel, 3.2 g/hp-hr. and (3) diesel, 3.7 g/hp-hr.

The standard deviation of the uncontrolled NO_x emission data base is relatively large compared to the sales-weighted average uncontrolled NO_x emission level for each engine type. This indicates that the distribution of uncontrolled NO_x emissions levels is quite broad. In addition, the standard deviation is of the same magnitude as the 40 percent reduction in NO_x emissions that can be achieved. Thus, regardless of which alternative approach is followed to select the numerical NO_x concentration emission limit, a significant portion of the IC engine population may have to achieve more or less than a 40 percent reduction in NO_x emissions to comply with the standards.

It is important to note that the 40 percent reduction in NO_x emissions is based on the application of a single control technique, such as ignition retard, or air-to-fuel ratio change. Other emission control techniques, however, such as manifold air cooling and engine derate, exist, although they are generally not as effective in reducing NO_x emissions. Since emission control techniques are additive to some extent, it is possible in a number of cases to reduce NO_x emissions by greater than 40 percent.

The following factors were examined for each engine type to choose the alternative for selecting the numerical NO_x concentration emission limit: (1) The percentage of engines that would have to reduce NO_x emissions by 40 percent or less to meet the standards; (2) the percentage of engines that would be required to do nothing to meet the standards; and (3) the percentage of engines that would be required to reduce NO_x emissions by more than 40 percent to meet the standards. The normal distribution curve presented in Figure I illustrates the trade-offs among the three alternatives for selecting the numerical NO_x concentration emission limit.

The first alternative is to apply the 40 percent reduction to the highest uncontrolled NO_x emission level within a fuel category. For example, 29 g/hp-hr is the highest uncontrolled NO_x emission level for gas engines. The application of a 40 percent reduction would lead to an emission level of about 17 g/hp-hr. As illustrated in Figure I, if this level were selected as a standard of performance, 99 percent of production gas engines could easily meet the emission limit by reducing emissions by 40 percent or less. However, 69 percent of production engines would not have to reduce NO_x emissions at all. Only one percent of production engines would have to reduce NO_x emissions by more than 40 percent.

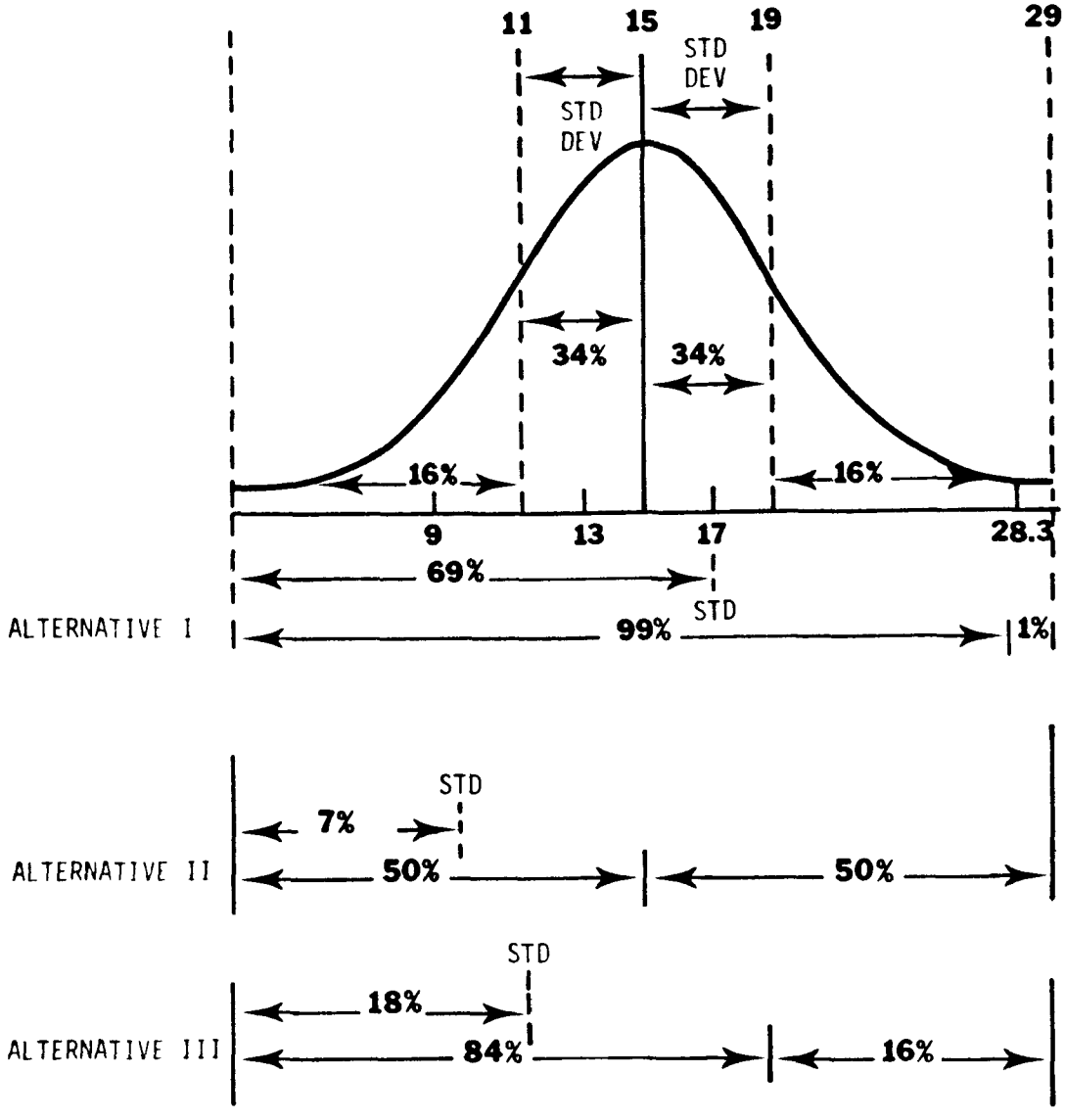


FIGURE 1. Statistical effects of alternative emission limits on gas engines.

The second alternative is to apply 40 percent reduction to the sales-weighted average uncontrolled NO_x emission level. For example, the sales-weighted avergage uncontrolled NO_x level for gas engines is 15 g/hp-hr. The application of a 40 percent reduction would lead to a NO_x emission level of 9 g/hp-hr. As illustrated in Figure I, if this level were selected as a standard of performance, 50 percent of production gas engines could meet the standard with 40 percent or less reduction in NO_x emissions. However, 50 percent of production gas engines would be required to reduce NO_x emissions by greater than 40 percent. Only seven percent of production gas engines would not have to reduce NO_x emissions at all.

The third alternative is to base the standards on a 40 percent reduction in NO_x emissions from the sales-weighted average uncontrolled NO_x emission level plus one standard deviation. For example, the sales-weighted average uncontrolled NO_x emission level for gas production gas engines is 15 g/hp-hr and the standard deviation of the production gas engine data base is 4 g/hp-hr. Thus, the application of a 40 percent reduction to the sum of these two values would lead to an emission level of 11 g/hp-hr. As illustrated in Figure I, if this level were selected as a standard of performance, 84 percent of the production gas engines could easily meet the emission limit by reducing emissions by 40 percent or less. However, 18 percent of the production gas engines would not have to reduce NO_x emission at all. Only 16 percent of the production gas engines would have to reduce NO_x emissions by more than 40 percent.

This same analysis applied to dual-fuel and diesel engines leads to the results summarized in Table III. If standards of performance were based on Alternative I, essentially all engines could achieve the emission limit by reducing NO_x emissions 40 percent or less. A significant reduction in NO_x emissions would not be achieved, however, since 50 to 70 percent of the IC engines would not have to reduce NO_x emissions at all. If the standards of performance were based on Alternatve II, about 50 percent of the IC engines (in all categories) would have to reduce NO_x emissions by greater than 40 percent. Less than 10 percent would not have to reduce NO_x emissions at all. Thus this alternative would achieve a significant reduction in NO_x emissions from new sources. If standards of performance were based on Alternative III, the results would be similar to those achieved with Alternative I. About 85 percent of engines could easily meet the standards by reducing NO_x emissions by less than 40 percent. About 20 to 30 percent of IC engines would not have to reduce NO_x emissions at all, and about 15 percent of IC engines would have to reduce NO_x emissions by more than 40 percent.

In light of the high priority which has been given to standards directed toward reducing NO_x emissions and the significance of IC engines in terms of their contribution to NO_x emissions from stationary sources, the second alternative was chosen for selecting the NO_x emission concentration limit. This approach will achieve the greatest reduction in NO_x emissions from new IC engines.

TABLE III

SUMMARY OF STATISTICAL ANALYSES OF ALTERNATE EMISSION LIMITS

GAS ENGINES

Alternative	I	II	III
Standard	17	9	11
Percent required to apply less than or equal to 40 percent control	99	50	84
Percent required to do nothing	69	7	18
Percent required to apply more than 40 percent control	1	50	16

DUAL-FUEL ENGINES

Alternative	I	II	III
Standard	9	5	7
Percent required to apply less than or equal to 40 percent control	98	54	87
Percent required to do nothing	62	18	48
Percent required to apply more than 40 percent control	2	46	13

DIESEL ENGINES

Alternative	I	II	III
Standard	11	7	9
Percent required to apply less than or equal to 40 percent control	98	56	86
Percent required to do nothing	50	4	29
Percent required to apply more than 40 percent control	2	44	14

Selection of limits.—A concentration (ppm) format was selected for the standards. Consequently, the brake-specific NO_x emission limits corresponding to the second alternative for selecting numerical emission limits (i.e., gas – 9 g/hp-hr; dual-fuel – 5 g/hp-hr; diesel – 7 g/hp-hr) must be converted to concentration limits (corrected to 15 percent O_2 on a dry basis). This may be done by dividing the brake-specific volume of NO_x emissions by the brake-specific total exhaust gas volume. Determining the brake-specific volume of NO_x emissions is straight-forward. Determining the brake-specific total exhaust gas volume is more complex, in that the brake-specific exhaust flow and the exhaust gas molecular weight are unknown. Knowing the fuel heating value and composition, the brake-specific fuel consumption, and assuming 15 percent excess air, however, defines these unknowns. (The complete derivation is explained in detail in the Standards Support and Environmental Impact Statement.) Combining these factors leads to the following conversion factor:

$$NO_x = \frac{\left(\frac{10^6}{46}\right) \times (BSNO_x)}{\left(\frac{16.6 + 3.29\ Z}{12.0 + Z}\right) \times (BSFC)}$$

where:

NO_x = NO_x concentration (ppm) corrected to 15 percent O_2.

$BSNO_x$ = Brake-specific NO_x emissions, g/hp-hr.

BSFC = Brake-specific fuel consumption, g/hp-hr.

Z = Hydrogen/Carbon ratio of the fuel.

For natural gas, a hydrogen-to-carbon (H/C) ratio of 3.5 and a lower heat value (LHV) of 20,000 Btu/lb was assumed. Diesel ASTM–2 has a H/C ratio of 1.8 and a LHV of 18,320 Btu/lb.

Applying this conversion factor to the brake-specific emission limits associated with the second alternative for selecting NO_x emissions limits leads to the NO_x concentration emission limits included in the proposed standards:

Engine	NO_x emission limit
Gas	700 ppm.
Dual-fuel/Diesel	600 ppm.

These emission limits have been rounded upward to the nearest 100 ppm to include a "margin" to allow for source variability. The standard for diesel engines has also been applied to dual-fuel engines. If a separate emission limit has been selected for dual-fuel engines, the corresponding numerical NO_x concentration emission limit would be 400 ppm. Sales of dual-fuel engines, however, have ranged from 17 to 95 units annually over the past five years, with a general trend of decreasing sales. Dual-fuel engines serve the same applications as diesel engines, and new dual-fuel engines will likely operate primarily as diesel engines because of increasingly limited natural gas supplies. Thus, the combining of dual-fuel engines with diesel engines for standards of performance will have little adverse impact and will simplify enforcement of the standards of performance.

The effect of ambient atmospheric conditions on NO_x emissions from large stationary IC engines can be significant. Therefore, to enforce the standards uniformly, NO_x emissions must be determined relative to a reference set of ambient conditions. All existing ambient correction factors were reviewed that could potentially be applied to large stationary IC engines to correct NO_x emissions to standard conditions.

The correction factors that were selected for both spark ignition (SI) and compression ignition (CI) engines are included in the proposed standards. For the compression ignition engines (i.e., diesel and dual-fuel), a single correction factor for both temperature and humididty was selected. For spark ignition engines (i.e., gas), separate correction factors were selected for humidity and temperature, and measured NO_x emissions are corrected to reference ambient conditions by multiplying these two factors together. No correction factor was selected for changes in ambient pressure because no generalized relationship could be determined from the very limited data that are available. These correction factors represent the general effects of ambient temperature and relative humidity on NO_x emissions, and will be used to adjust measured NO_x emissions during any performance test to determine compliance with the numerical emission limit.

Since the recommended factors may not be applicable to certain engine models, as an alternative to the use of these correction factors, engine manufacturers, owners, or operators may elect to develop their own ambient correction factors. All such correction factors, however, must be substantiated with data and then approved by EPA for use in determining compliance with NO_x emission limits. The ambient correction factor will be applied to all performance tests, not only those in which the use of such factors would reduce measured emission levels.

As discussed in "Standards Support and Environmental Impact Statement: Proposed Standards of Performance for Stationary Gas Turbines," EPA–450/2–77–017a, the contribution to NO_x emissions by the conversion of fuel-bound nitrogen in heavy fuel to NO_x can be significant for stationary gas turbines. The organic NO_x contribution to total gas turbine NO_x emissions is complicated by the fact that the percentage of fuel-bound nitrogen converted to NO_x decreases as the fuel-bound nitrogen level increases. Below a fuel-bound nitrogen level of about 0.05 percent, essentially 100 percent of the fuel-bound nitrogen is converted to NO_x Above a fuel-bound nitrogen level of about 0.4 percent, only about 40 percent is converted to NO_x.

As discussed in the Standards Support and Environmental Impact Statement, Volume I for Stationary Gas Turbines, assuming a fuel with 0.25 percent weight fuel-bound nitrogen (which allows approximately 50 percent availablility of domestic heavy fuel oil), controlled NO_x emissions would increase by about 50 ppm due to the contribution to NO_x emissions of fuel-bound nitrogen. In gas turbines, this contribution was significant when compared to the proposed emission limit of 75 ppm. However, for large IC engines, the contribution of fuel-bound nitrogen to NO_x emissions is likely to be small (approximately 10 percent). Sales of IC engines firing heavy fuels is insignificant and not expected to increase in the near future. Given that the emission limits have been rounded upward to the nearest 100 ppm and the potential contribution of fuel-bound nitrogen to NO_x emissions is very small, no allowance has been included for the fuel-bound nitrogen content of the fuel in determining compliance with the standards of performance.

Selection of Compliance Time Frame

Manufacturers of large-bore IC engines are generally committed to a particular design approach and, therefore, conduct extensive research, development, and prototype testing before releasing a new engine model for sale. Consequently, these manufacturers will require some period of time to alter or reoptimize and test IC engines to meet standards of performance. The estimated time span between the decision by a manufacturer to control NO_x emissions from an engine model and start of production of the first controlled engine is about 15 months for any of the four demonstrated emission control techniques. With their present facilities, however, testing can typically

be conducted on only two to three engine models at a time. Since most manufacturers produce a number of engine models, additional time is required before standards of performance become effective. In addition, a number of manufacturers produce their most popular engine models at a fairly steady rate of production and satisfy fluctuating demands from inventory. Consequently, additional time in necessary to allow manufacturers to sell their current inventory of uncontrolled IC engines before they must comply with standards of performance.

It is estimated that about 30 months delay in the applicability date of the standard is appropriate to allow manufacturers time to comply with the proposed standards of performance. In addition, in light of the stringency of the standards (i.e., many engine models will have to reduce NO_x emissions by more than 40 percent) this time period provides the flexibility for manufacturers to develop and use combinations of the control techniques upon which the standards are based or other control techniques. Consequently, 30 months from today's date is selected as the delay period for implementation of these standards on large stationary IC engines.

Selection of Monitoring Requirements

To provide a means for enforcement personnel to ensure that an emission control system installed to comply with standards of performance is properly operated and maintained, monitoring requirements are generally included in standards of performance. For stationary IC engines, the most straightforward means of ensuring proper operation and maintenance would be to monitor NO_x emissions released to the atmosphere.

Installed costs, however, for continuous monitors are approximately $25,000. Thus the cost of continuous NO_x emission monitoring is considered unreasonable for IC engines since most large stationary IC engines cost from $50,000 to $3,000,000 (i.e., 1000 hp gas production engine and 20,000 hp electrical generation engine).

A more simple and less costly method of monitoring is measuring various engine operating parameters related to NO_x emissions. Consequently, monitoring of exhaust gas temperature was considered since this parameter could be measured just after the combustion process during which NO_x is formed. However, a thorough investigation of this approach showed no simple correlation between NO_x emission and exhaust gas temperature.

A qualitative estimate of NO_x emissions, however, can be developed by measuring several engine operating parameters simultaneously, such as spark ignition or fuel injector timing, engine speed, and a number of other parameters. These parameters are typically measured at most installations and thus should not impose an additional cost impact. For these reasons, the emission monitoring requirements included in the proposed standards of performance require monitoring various engine operating parameters.

For diesel and dual-fuel engines, the engine parameters to be monitored are: (1) Intake manifold temperature; (2) intake manifold pressure; (3) rack position; (4) fuel injector timing; and (5) engine speed. Gas engines would require monitoring of (1) intake manifold temperature; (2) intake manifold pressure; (3) fuel header pressure; (4) spark timing; and (5) engine speed.

Another parameter that could be monitored for gas engines is the fuel heat value, since it can affect NO_x emissions significantly. Because of the high costs of a fuel heating value monitor, and the fact that many facilities can obtain the lower heating value directly from the gas supplier, monitoring of this parameter would not be required.

The operating ranges for each parameter over which the engine could operate and in which the engine could comply with the NO_x emission limit would be determined during the performance test. Once established, these parameters would be monitored to ensure proper operation and maintenance of the emission control techniques employed to comply with the standards of performance.

For facilities having an operator present every day these operating parameters would be recorded daily. For remote facilities, where an operator is not present every day, these operating parameters would be recorded weekly. The owner/operator would record the parameters and, if these parameters include values outside the operating ranges determined during the performance test, a report would be submitted to the Administrator on a quarterly basis identifying these periods as excess emissions. Each excess emission report would include the operating ranges for each parameter as determined during the performance test, the monitored values for each parameter, and the ambient air conditions.

Selection of Performance Test Method

A performance test method is required to determine whether an engine complies with the standards of performance. Reference Method 20, "Determination of Nitrogen Oxides, Sulfur Dioxide, and Oxygen emissions from Stationary Gas Turbines," which was proposed in the October 3, 1977 **Federal Register**, is proposed as the performance test method for IC engines. Reference Method 20 has been shown to provide valid results. Consequently, rather than developing a totally new reference test method, Reference Method 20 would be modified for use on IC engines.

The changes and additions to Reference Method 20 required to make it applicable for testing of internal combustion engines include (by section):

1. *Principle and Applicability.* Sulfur dioxide measurements are not applicable for internal combustion engine testing.

6.1 Selection of a sampling site and the minimum number of traverse points.

6.11 Select a sampling site located at least five stack diameters downstream of any turbocharger exhaust, crossover junction, or recirculation take-offs and upstream of an dilution air inlet. Locate the sample site no closer than one meter or three stack diameters (whichever is less) upstream of the gas discharge to the atmosphere.

6.1.2 A preliminary O_2 traverse is not necessary.

6.1.2.2 Cross-sectional layout and location of traverse points use a minimum of three sample points located at positions of 16.7, 50 and 83.3 percent of the stack diameter.

6.2.1 Record the data required on the engine operation record on Figure 20.7 of Reference Method 20. In addition, record (a) the intake manifold pressure; (b) the intake manifold temperature; (c) rack position; (d) engine speed; and (e) injector or spark fuming. (The water or steam injection rate is not applicable to internal combustion engines.)

NO_x emissions measured by Reference Method 20 will be affected by ambient atmospheric conditions. Consequently, measured NO_x emissions would be adjusted during any performance test by the ambient condition correction factors discussed earlier, or by custom correction factors approved for use by EPA.

The performance test may be performed either by the manufacturer or at the actual user operating site. If the test is performed at the manufacturer's facility, compliance with that performance test will be sufficient proof

of compliance by the user as long as the engine operating parameters are not varied during user operation from the settings under which testing was done.

Public Hearing

A public hearing will be held to discuss these proposed standards in accordance with section 307(d)(5) of the Clean Air Act. Persons wishing to make oral presentations should contact EPA at the address given in the ADDRESSES Section of this preamble. Oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement with EPA before, during, or within 30 days after the hearing. Written statement should be addressed to Mr. Jack R. Farmer (see ADDRESSES Section).

The docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The principal purposes of the docket are (1) to allow interested parties to identify and locate documents so that they can intelligently and effectively participate in the rulemaking process, and (2) to serve as the record for judicial review. The docket requirement is discussed in section 307(d) of the Clean Air Act.

Miscellaneous

As prescribed by Section 111 of the Act, this proposal is accompanied by the Administrator's determination that emissions from stationary IC engines contribute to air pollution which causes or contributes to the endangerment of public health or welfare, and by publication of this determination in this issue of the **Federal Register**. In accordance with section 117 of the Act, publication of these standards was preceded by consultation with appropriate advisory committees, independent experts, and federal department and agencies. The Administrator welcomes comments on all aspects of the proposed regulations, including the designation of stationary IC engines as a significant contributor to air pollution which causes or contributes to the endangerment of public health or welfare, economic and technological issues, monitoring requirements and the proposed test method.

Comments are specifically invited on the severity of the economic and environmental impact of the proposed standards on stationary naturally aspirated carbureted-gas IC engines since some parties have expressed objection to applying the proposed standards to these engines. Comments are also invited on the selection of rotary engines for control by standards of performance. These engines were included because they are expected to be contributors to NO_x emissions from stationary sources and can be controlled by demonstrated NO_x emission control techniques. Any comments submitted to the Administrator on these issues, however, should contain specific information and data pertinent to an evaluation of the magnitude of this impact, its severity, and its consequences.

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect:

> The degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated (section 111(a)(1)).

Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be seclected as the basis of standards of performance because of costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act may require the imposition of a more stringent emission standard emission in several situations.

For example, applicable costs do not necessarily play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources located in nonattainment areas (i.e., those areas where statutorily mandated health and welfare standards are being violated). In this respect, section 173 of the Act requires that new or modified sources constructed in an area which exceeds the National Ambient Air Quality Standard (NAAQS) must reduce emissions to the level which reflects the "lowest achievable emission rate" (LAER), as defined in section 171(3). The statute defines LAER as that rate of emissions which reflects:

> (A) The most stringent emission limitation which is contained in the implementation plan of any state for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable or
>
> (B) The most stringent emission limitation which is acheved in practice by such class or category of source, whichever is more stringent.

In no event can the emission rate exceed any applicable new source performance standard.

A similar situation may arise under the prevention-of-significant-deterioration-of-air-quality provisions of the Act. These provisions require that certain sources employ "best available control technology" (BACT) as defined in section 169(3) for all pollutants regulated under the Act. Best available control technology must be determined on a case-by-case basis, taking energy, environmental and economic impacts, and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the Act.

In all cases, State Implementation Plans (SIP's) approved or promulgated under section 110 of the Act must provide for the attainment and maintenance of NAAQS designed to protect public health and welfare. For this purpose, SIP's must in some cases require greater emission reduction than those required by standards of performance for new sources.

Finally, states are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Accordingly new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

Under EPA's "new" sunset policy for reporting requirements in regulations, the reporting requirements in this regulation will automatically expire five years from the date of promulgation unless EPA takes affirmative action to extend them.

EPA will review this regulation four years from the date of promulgation This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, and improvements in emissions control technology.

An economic impact assessment has been prepared as required under section 317 of the Act and is included in the Standards Support and Environmental Impact Statement.

Dated: July 11, 1979.

Douglas M. Costle.

Administrator.

It is proposed to amend Part 60 of Chapter I, Title 40 of the Code of Federal Regulations as follows:

1. By adding Subpart FF as follows:

Subpart FF—Standards of Performance for Stationary Internal Combustion Engines

Sec.

60.320 Applicability and designation of affected facility.
60.321 Definitions.
60.322 Standards for nitrogen oxides.
60.323 Monitoring of operations.
60.324 Test methods and procedures.

Authority: Secs. 111 and 301(a) of the Clean Air Act, as amended, (42 U.S.C. 1857c-7, 1857g(a)), and additional authority as noted below.

Subpart FF—Standards of Performance for Stationary Internal Combustion Engines

§ 60.320 Applicability and designation of affected facility.

The provisions of this subpart are applicable to the following affected facilities which commence construction beginning 30 months from today's date:

(a) All gas engines that are either greater than 350 cubic inch displacement per cylinder or equal to or greater than 8 cylinders and greater than 240 cubic inch displacement per cylinder.

(b) All diesel or dual-fuel engines that are greater than 560 cubic inch displacement per cylinder.

(c) All rotary engines that are greater than 1500 cubic inch displacement per rotor.

§ 60.321 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act or in subpart A of this part.

(a) "Stationary internal combustion engine" means any internal combution engine, except gas turbines, that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) "Emergency standby engine" means any stationary internal combustion engine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable during an emergency situation.

(c) "Reference ambient conditions" means standard air temperature (29.4°C, or 85°F), humidity (17 grams H_2O/kg dry air, or 75 grains H_2O/lb dry air), and pressure (101.3 kilopascals, or 29.92 in. Hg.).

(d) "Peak load" means operation at 100 percent of the manufacturer's design capacity.

(e) "Diesel engine" means any stationary internal combustion engine burning a liquid fuel.

(f) "Gas enine" means any stationary internal combustion engine burning a gaseous fuel.

(g) "Dual-fuel engine" means any stationary internal combustion engine that is burning liquid and gaseous fuel simultaneously.

(h) "Unmanned engine" means any stationary internal combustion engine installed and operating at a location which does not have an operator regularly present at the site for some portion of a 24-hour day.

(i) "Non-remote operation" means any engine installed and operating at a loction which has an operator regularly present at the site for some portion of a 24-hour day.

(j) "Brake-specific fuel consumption" means fuel input heat rate, based on the lower heating value of the fuel, expressed on the basis of power output (i.e., (k]/w-hr).

(k) "Weekly basis" means at seven day intervals.

(l) "Daily basis" means at 24 hours intervals.

(m) "Rotary engine" means any Wankel type engine where energy from the combustion of fuel is converted directly to rotary motions instead of reciprocating motion.

(n) "Displacement per rotor" means the volume contained in the chamber of a rotary engine between one flank of the rotor and the housing at the instant the inlet port is closed.

§ 60.322 Standards for nitrogen oxides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere, except as provided in paragraphs (b) and (c) of this section—

(1) From any gas engine, with a brake-specific fuel consumption at peak load more than or equal to 10.2 kilojoules/watt-hour any gases which contain nitrogen oxides in excess of 700 parts per million volume, corrected to 15 percent oxygen on a dry basis.

(2) From any diesel or dual-fuel engine with a brake-specific fuel consumption at peak load more than or equal to 10.2 kilojoules/watt-hour any gases which contain nitrogen oxides in excess of 600 parts per million volume, corrected to 15 percent oxygen on a dry basis.

(3) From any stationary internal combustion engine with a brake-specific fuel consumption at peak load of less than or equal to 10.2 kilojoules/watt-hour any gases which contain nitrogen oxides in excess of:

(i) $STD = 700 \frac{10.2}{Y}$ for any gas engine,

(ii) $STD = 600 \frac{10.2}{Y}$ for any diesel or dual-fuel engine

where:

STD = allowable NO_x emissions (parts-per-million volume corrected to 15 percent oxygen on a dry basis).

Y = manufacturer's rated brake-specific fuel consumption at peak load (kilojoules per watt-hour) or owner/operator's brake-specific fuel consumption at peak load as determined in the field.

(b) All one and two cylinder reciprocating gas engines are exempt from paragraph (a) of this section.

(c) Emergency standby engines are exempt from paragraph (a) of this section.

§ 60.323 Monitoring of operations.

(a) The owner or operator of any stationary internal combustion engine, subject to the provisions of this subpart must, on a weekly basis for unmanned engines and on a daily basis for manned engines, monitor and record the following parameters. All monitoring systems shall be accurate to within five percent and shall be approved by the Administrator.

(1) For diesel and dual-fuel engines:
(i) Intake manifold temperature
(ii) Intake manifold pressure
(iii) Engine speed
(iv) Diesel rack position (fuel flow)
(v) Injector timing
(2) For gas engines:
(i) Intake manifold temperature
(ii) Intake manifold pressure
(iii) Fuel header pressure
(iv) Engine speed
(v) Spark ignition timing

(b) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as any daily (for manned engines) or weekly (for unmanned engines) period during which any one of the parameters specified under paragraph (a) of this section falls outside the range identified for that parameter udner § 60.324(a)(3). Each excess emission report shall include the range identified for each operating parameter under § 60.324(a)(4), the monitored value for each operating parameter specified under § 60.323(a),

the ambient air conditions during the period of excess emissions, and any graphs and/or figures developed under § 60.324(a)(4)

(Sec. 114 of the Clean Air Act, as amended (42 U.S.C. 1857c-9))

§ 60.324 Test methods and procedures.

The reference methods in Appendix A to this part, except as provided in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.322 as follows:

(a) Reference Method 20 for the concentration of nitrogen oxides and oxygen. The span for the nitrogen oxides analyzer used in this method shall be 1500 ppm.

(1) The following changes and additions (by section) to Reference Method procedures should be followed when determining compliance with § 60.322:

1. *Principle and Applicability.* Sulfur dioxide measurements are not applicable for internal combustion engine testing.

6.1 Selection of a sampling site and the minimum number of traverse points.

6.11 Select a sampling site located at least five stack diameters downstream of any turbocharger exhaust, crossover junction, or recirculation take-offs and upstream of any dilution air inlet. Locate the sample site no closer than one meter or three stack diameters (whichever is less) upstream of the gas discharge to the atmosphere.

6.1.2 a preliminary O_2 traverse is not necessary.

6.2 Cross-sectional layout and location of traverse points. Use a minimum of three sample points located at positions of 16.7, 50 and 83.3 percent of the stack diameter.

6.2.1 Record the data required on the engine operation record on Figure 20.7 of Reference Method 20. In addition, record (a) the intake manifold pressure; (b) the intake manifold temperature; (c) rack position, fuel header pressure or carburetor position; (d) engine speed; and (e) injector or spark timing. (The water or steam injection rate is not applicable to internal combustion engines.)

(2) The nitrogen oxides emission level measured by Reference Method 20 shall be adjusted to reference ambient conditions by the following ambient condition correction factors:

NO_x corrected = (K) NO_x observed

where K is determined as follows:

Fuel	Correction Factor
Diesel and Dual-Fuel	$K = 1/(1 + 0.00235(H - 75) + 0.00220\ (T - 85))$
Gas	$K = (K_H)\ (K_T)$ $K_H = 0.844 + 0.151\ (\frac{H}{100}) + 0.075\ (\frac{H}{100})^2$ $K_T = 1 - (T - 85)(0.0135)$

where:

H = observed humidity, grains H_2O/lb dry air

T = observed inlet air temperature, °F

The adjusted NO_x emission level shall be used to determine compliance with § 60.322.

(3) Manufacturers, owners, or operators may develop custom ambient correction factors in terms of ambient air temperature and/or pressure, and/or humidity to adjust the nitrogen oxide emission level measured by the performance test to reference ambient conditions. These correction factors must be substantiated with data and must be approved by the Administrator before they can be used to determine compliance with § 60.322. Notices of approval of custom ambient condition correction factors will be published in the Federal Register.

(4) Testing shall be conducted and ranges identified for each parameter specified under § 60.323(a) over which the numerical emission limits included under § 60.322 are not exceeded. This will be accomplished by measuring NO_x emissions, using Reference Method 20, and these parameters at four points over the normal load range of the internal combustion engine, including the minimum and maximum points in the range if the stationary internal combustion engine will be operated over a range of load conditions.

(b) ASTM D-2382 shall be used to determine the lower heating value of liquid fuels and ASTM D-1826 shall be used to determine the lower heating value of gaseous fuels.

(Sec. 114 of the Clean Air Act, as amended (42 U.S.C. 1857c-9))

[FR Doc 79-22224 Filed 7-20-79, 8 45 am]

[FRL 1099-6]

Air Pollution Prevention and Control; Addition to the List of Categories of Stationary Sources

Section 111 of the Clean Air Act (42 U.S.C. 1857c-6) directs the Administrator of the Environmental Protection Agency to publish, and from time to time revise, a list of categories of stationary sources which he determines may contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare. Within 120 days after the inclusion of a category of stationary sources in such list, the Administrator is required to propose regulations establishing standards of performance for new and modified sources within such category. At present standards of performance for 27 categories of sources have been promulgated.

The Administrator, after evaluating available information, has determined that stationary internal combustion engines are an additional category of stationary sources which meets the above requirements. The basis for this determination is discussed in the preamble to the proposed regulation that is published elsewhere in this issue of the Federal Register. Evaluation of other stationary source categories is in progress, and the list will be revised from time to time as the Administrator deems appropriate. Stationary internal combustion engines are included on the proposed NSPS priority list (published August 31, 1978) required by section 111(f)(1), but since the priority list is not final, stationary internal combustion engines are also being listed as indicated below at this time. Once the priority list is promulgated, all source categories on the promulgated list are considered listed under section 111(b)(1)(A), and separate listings such as this will not be made for those source categories.

Accordingly, notice is given that the Administrator, pursuant to section 111(b)(1)(A) of the Act, and after consultation with appropriate advisory committees, experts and Federal departments and agencies in accordance with section 117(f) of the Act, effective July 23, 1979 amends the list of categories of stationary sources to read as follows:

List of Categories of Stationary Sources and Corresponding Affected Facilities

* * * * *

Source Category

* * * * *

Affected Facilities

Internal combustion engines

Proposed standards of performance applicable to the above source category appear elsewhere in this issue of the Federal Register.

Dated: July 11, 1979.

Douglas M. Costle,

Administrator./

[FR Doc 79-22225 Filed 7-20-79, 8 45 am]

[40 CFR Part 60]

[FRL 1321-5]

Standards of Performance for New Stationary Sources; Stationary Internal Combustion Engines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Extension of Comment Period.

SUMMARY: The deadline for submittal of comments on the proposed standards of performance for stationary internal combustion engines, which were proposed on July 23, 1979 (44 FR 43152), is being extended from September 21, 1979, to October 22, 1979.

DATES: Comments must be received on or before October 22, 1979.

ADDRESSES: Comments should be submitted to Mr. David R. Patrick, Chief, Standards Development Branch (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

FOR FURTHER INFORMATION CONTACT: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5271.

SUPPLEMENTARY INFORMATION: On July 23, 1979 (44 FR 43152), the Environmental Protection Agency proposed standards of performance for the control of emissions from stationary internal combustion engines. The notice of proposal requested public comments on the standards by September 21, 1979. Due to a delay in the shipping of the Standards Support Document, sufficient copies of the document have not been available to all interested parties in time to allow their meaningful review and comment by September 21, 1979. EPA has received a request from the industry to extend the comment period by 30 days through October 22, 1979. An extension of this length is justified since the shipping delay has resulted in approximately a three-week delay in processing requests for the document.

Additionally, page 9-75 of the Standards Support Document was inadvertently omitted. Persons wishing to obtain copies of this page should contact Mr. Doug Bell, Emission Standards and Engineering Division, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5477.

Dated: September 12, 1979.

David G. Hawkins,

Assistant Administrator for Air, Noise, and Radiation.

[FR Doc. 79-28827 Filed 9-17-79; 8.45 am]

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

SECONDARY LEAD SMELTERS

SUBPART L

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1415-3]

Standards of Performance for New Stationary Sources: Secondary Lead Smelters; Review of Standards

AGENCY: Environmental Protection Agency.

ACTION: Review of standards.

SUMMARY: EPA has reviewed the standards of performance for secondary lead smelters (40 CFR 60.120). The review is required under the Clean Air Act, as amended August 1977. The purpose of this notice is to announce EPA's plans to undertake a program which will be designed, depending upon its findings, to develop fugitive particulate matter emission standards and SO_2 standards applicable to secondary lead smelters.

DATE: Comments must be received by June 16, 1980.

ADDRESS: Comments should be submitted to the Central Docket Section (A-130), U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460, Attention: Docket No. A-79-20.

FOR FURTHER INFORMATION CONTACT:

Mr. Robert Ajax, telephone: (919) 541-5271. The document "A Review of Standards of Performance for New Stationary Sources—Secondary Lead Smelters," EPA-450/3-79-015, is available upon request from Mr. Robert Ajax (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

SUPPLEMENTARY INFORMATION:

Introduction

On June 11, 1973, the Environmental Protection Agency proposed a standard under Section 111 of the Clean Air Act to control particulate matter emissions from secondary lead smelters. The standard, promulgated on March 8, 1974, and amended on April 17 and October 6, 1975, applies to any secondary lead smelter under construction, modification, or reconstruction on or after June 11, 1973. The specific lead smelter facilities subject to the standard are reverberatory furnaces (stationary, rotating, rocking, or tilting), blast (cupola) furnaces and pot furnaces of more than 550-lb charging capacity. Furnaces for smelting lead alloy for newspaper linotype are subject to the standards if they meet the same size requirement as applied to pot furnaces.

The Clean Air Act Amendments of 1977 require that the Administrator of EPA review and, if appropriate, revise established standards of performance for new stationary sources at least every 4 years (Section 111(b)(1)(B)). Following the adoption of the amendments, EPA contracted with the MITRE Corporation to undertake a survey of available literature and information pertaining to secondary lead processes, emissions and control technologies, including results from tests of new lead smelters to assess the need for revision of the standard. The survey involved visits to each EPA Regional Office as well as review of recent literature and study results, but did not include visits to plants. Based principally on this review, EPA plans to begin a program to develop standards which would limit the emission of fugitive particulate matter, and sulfur dioxide from secondary lead smelters. This program will include an extensive technical investigation and assessment. Final decisions pertaining to whether standards should be adopted and the level of any such standards will not be made until after these investigations and assessments are completed. The time required to develop these standards for proposal will be approximately 2 years.

Industry Review

Secondary lead produced by smelting of scrap accounts for roughly half of all lead produced in the United States. After a record output of over 626,000 tons in 1976, secondary lead output declined in 1977 to between 588,000 and 600,000 tons. However, production of lead from both primary and secondary sources is expected to grow at an annual rate of slightly under 2 percent or by about 50 percent between 1976 and 2000. This compares with an average annual increase in demand for lead from 1967 to 1976 of about 3 percent. It is expected that the relative share of the market held by secondary lead production will remain near the 50 percent level.

It is estimated, based on an assumed secondary smelter capacity of 50 ton/day, that on the average, two new plants and one to two modified smelters will become subject to NSPS each year. This estimate is consistent with the latest Bureau of Mines data (1978) which show six plants completed or scheduled for completion in the 1977-1979 period (including major expansions of existing plants). Through 1978, six plants have been identified which have come on line subject to the standard.

The secondary lead market is dominated by a few companies. In addition, the trend is toward fewer and larger plants as evidenced by the decrease in the total number of smelters from 160 in 1967 to about 115 in 1975. Overall, the average annual output per smelter is in the range of 5,700 to 6,000 tons. Geographically, the industry is somewhat dispersed with secondary lead smelters located in all of the ten EPA regions.

Emissions and Control Technology

Process Particulate Emissions. The present standard of performance limits the emission of particulate matter from blast or reverberatory furnaces to 50 mg/dscm (0.022 gr/dscf) and to less than 20 percent opacity. In addition, the standard limits the opacity of emissions from pot furnaces to less than 10 percent opacity. For a typical reverberatory or blast furnace with uncontolled emissions of 147 lbs/ton and 193 lbs/ton of feed material respectively, the standard limits emissions to one and 2 lbs/ton. This compares to an estimated controlled emission level of 21 and 28 lbs/ton in the absence of the new source standard. In this review, results from four compliance tests were obtained. The results from reverberatory and blast furnace tests were 0.015 gr/dscf and 0.0135 gr/dscf respectively.

Lead Emissions. The present standard of performance does not specifically limit the atmospheric emission of lead from secondary lead furnaces. However, lead is controlled by the same devices employed to limit particulate matter emissions. Reported lead emission data, although variable, indicate uncontrolled lead emissions to be approximately 23 percent of the total particulate matter emissions. Controlled lead emissions measured in six tests conducted on emissions from seven furnaces were found to range in concentration from 0.009 to 0.0846 lb/ton with five of the six below 0.04 lb/ton. In another survey of 11 controlled secondary lead smelters in the Chicago area, an emission rate of 0.002 lbs lead/ton of product was reported. Results of a further test at a baghouse controlled reverberatory furnace indicated particulate matter and lead concentrations of 0.016 and 0.001 gr/dscf, respectively. The variability in these data and the lack of other simultaneous inlet and outlet data do not allow a precise statement of relative control effectiveness. However, the data do consistently indicate that the ratio of lead to particulate emissions from controlled furnaces is not higher than the ratio (i.e., 23 percent) for uncontrolled furnaces.

Fugitive Emissions. In addition to the material discharged through the stack of a secondary lead furnace, particulate

and gaseous matter may be emitted into the atmosphere in and around a plant from other operations. Some of these fugitive emissions are process-related, e.g., when materials escape from the hoods provided around potential outlet points of a furnace. Others result from auxiliary operations. No fugitive emission points, whether related to processing or to auxiliary operations at the site, are currently subject to specific control under NSPS for secondary lead smelters.

In some situations, fugitive emissions may be high. For example, the high concentration of lead, particularly in the soil, close to two Toronto smelters was ascribed by Canadian investigators to "low-level, dust-producing operations rather than * * * stack fumes." In apparently extreme situations, fugitive particulate emissions from processing may amount to over 15 lb/ton of charge from reverberatory furnaces and as much as 12 lb/ton from blast furnaces. These rates, although much lower than uncontrolled emission rates from furnace stacks, are substantially higher than rates from stacks meeting the NSPS.

Several techniques have been applied to reduce fugitive emission rates and recently significant improvements in the technology for controlling fugitive emissions from both process- and site-related operations in secondary smelting of lead have been reported in Denmark. The methodology uses improved furnaces that minimize the escape of dusts during smelting and also enable baghouse contents to be recharged as collected, thereby eliminating the accumulation of these fines in storage piles where they are subject to transport into the environment. Specialized waste management and housekeeping procedures are used in conjuction with the furnaces to reduce the opportunity for emissions from storage of raw materials and other sources on the site. The technology has been investigated by the EPA Industrial Environmental Research Laboratory in Cincinnati in connection with the National Institute of Occupational Safety and Health (NIOSH). Testing of the furnaces has been conducted under the joint auspices of EPA and NIOSH at a plant in Denmark. Initial reports indicate the technology as having high potential for application in reducing fugitive emissions from secondary lead smelters in the United States.

Sulfur Dioxide. The rate of uncontrolled emissions of SO_2 from secondary lead smelters is approximately 76 lb/ton of lead produced for blast furnaces and of 114 lb/ton for reverberatory furnaces. A reverberatory furnace of 50 tons/day (2.08 tons/hr) would emit about 2.8 tons of SO_2 each day and a blast furnace of the same capacity about 1.9 tons. Assuming an equal mix between blast and reverberatory furnace production, the total secondary lead production in 1975 of 658,500 tons would have resulted in about 31,000 tons of SO_2. Currently, no NSPS for SO_2 from secondary lead smelters are in effect.

SO_2 control is not normally practiced at lead smelters. However, both regenerative SO_2 control systems which are used in the primary smelting industry to control SO_2 and produce sulfuric acid, and non-regenerative scrubbing systems used to control SO_2 emissions from steam generators are potentially applicable to SO_2 control at secondary lead smelters. A more detailed engineering assessment is needed to further assess the applicability of these technologies to determine the best demonstrated control technology and an appropriate level for any standard. In addition, the cost of SO_2 control and the associated economic impact require further study as these may be the primary consideration in analyzing the feasibility of control.

Conclusions

EPA believes that the information obtained in this review of the secondary lead industry does not provide a basis for determining conclusively that the standard should be revised nor at what level any revised standard should be set. However, the available data show that a project should be undertaken to further assess the need for and, as appropriate to develop standards limiting fugitive particulate matter (including lead) and sulfur dioxide emissions from secondary lead plants.

The available particulate matter compliance test data obtained in this review are consistent with the test data used by EPA in establishing the present standard and, although very limited, these data, added to the data used in developing the present standard support the validity of the present standard. Similarly, the data available on lead emissions from furnace stacks suggest that the particulate matter standard is adequate to require installation of control systems which represent best available control technology for both particulate matter and lead. Therefore, a separate standard for lead is considered unnecessary. EPA will welcome any additional data pertaining to this decision on the particulate matter standard and on lead emissions. In addition, EPA in the planned standards development discussed below, will seek to obtain additional recent compliance test data and will assess this in terms of the current standard.

The project to assess the need for and, as appropriate, to develop fugitive particulate matter and sulfur dioxide standards will be undertaken by EPA's Emission Standards and Engineering Division. This project is expected to begin early in 1980 and will follow a standardized approach which involves detailed engineering and economic assessments preceeding proposal of any standards. Standards resulting from this project would be proposed for comment in early 1982.

Dated: April 9, 1980.

Douglas M. Costle,

Administrator.

[FR Doc. 80-11666 Filed 4-16-80; 8.45 am]

BILLING CODE 6560-01-M

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

ELECTRIC ARC FURNACES (STEEL INDUSTRY)

SUBPART AA

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1415-2]

Review of Standards of Performance for New Stationary Sources; Electric Arc Furnaces (Steel Industry)

AGENCY: Environmental Protection Agency.

ACTION: Proposed Rule.

SUMMARY: EPA has reviewed its standards of performance for electric arc furnaces in the steel industry (40 CFR 60.270, Subpart AA) as required under the Clean Air Act, as amended August 1977. EPA intends to explore revising the standards to reflect demonstrated best available control technology for electric arc furnaces and would add argon-oxygen decarbonization (AOD) furnaces to the standard. Visible emission limitations would be reduced to be consistent with improved control technology.

DATES: Comments must be received by June 20, 1980.

ADDRESSES: Send comments to: Central Docket Section (A-130), U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460, Attention: Docket A-79-33. Comments should be submitted in duplicate if possible.

FOR FURTHER INFORMATION CONTACT: Mr. Stanley T. Cuffe, Telephone: (919) 541-5295. The document "A Review of Standards of Performance for Electric Arc Furnaces in the Steel Industry" is available upon request from Mr. Stanley T. Cuffe, (MD-13), Chief, Industrial Studies Branch, Emission Standards and Engineering Division, U.S. Environmental Protection Agency, Research Triangle Park, N.C. 27711.

SUPPLEMENTARY INFORMATION:

Background

On October 21, 1974, EPA proposed a standard under Section 111 of the Clean Air Act to control particulate matter emissions from electric arc furnaces (EAF) in the steel industry. The standard, promulgated on September 23, 1975, applies to any facility constructed or modified after October 21, 1974. The standard for particulate matter under § 60.272 limits the discharge to atmosphere from an electric arc furnace of any gases that:

1. Contain particulate matter in excess of 12 mg/dscm (0.0052 gr/dscf).
2. Exhibit 3 percent opacity or greater from a control device.
3. Exhibit greater than zero opacity from a shop, due solely to operation of any EAF(s), except:
   a. Shop opacity greater than zero percent, but less than 20 percent, may occur during charging periods.
   b. Shop opacity greater than zero percent, but less than 40 percent, may occur during tapping periods.
   c. Zero opacity from a shop shall apply only during periods when process flow rates and pressures are being monitored.
   d. Where the capture system is operated such that the roof of the shop is closed during the charge and the tap, and emissions to the atmosphere are prevented until the roof is opened after completion of the charge or tap, the shop opacity standards shall apply when the roof is opened and shall continue to apply for the length of time defined by the charging and/or tapping periods.

The standard for particulate matter also limits the discharge to atmosphere from dust handling equipment any gases which exhibit 10 percent opacity or greater.

The Clean Air Act Amendments of 1977 that require the Administrator of EPA review, establish standards of performance for new stationary sources (NSPS) at least every 4 years, and revise them as appropriate [Section 111(b)(1)(B)]. EPA has completed such a review of the standard of performance for electric arc furnaces in the steel industry and has decided to begin a project to revise the standard. EPA invites comments on this decision and on the findings on which it is based.

Findings

Industry Statistics

In 1972, there were approximately 299 EAF's in the United States. In 1977, there were approximately 303 EAF's being operated in the United States. However, about 30 EAF's were being installed between 1974 and 1979, which indicates that some older furnaces were probably shutdown and replaced. Only five of the new furnaces were subject to the standards.

Information on planned new facilities or modifications is limited by the reluctance of industry to state future plans because of current economic uncertainties. Nevertheless, EAF production should continue to increase. An EAF is flexible, can operate wholly on steel scrap, is adapted to ultrarapid melting, can make specialty steels, and can be quickly brought on line or taken off production. In addition, an EAF is relatively low in pollution potential, and emission controls are well demonstrated. These EAF advantages are substantiated by industry statistics showing that production in 1977 was about 25.4 Mg (27.9 million tons) and 29 Mg (31.9 million tons) in 1978 versus 21.5 Mg (23.7 million tons) in 1972, when the NSPS document was being developed.

Emissions and Control Technology

The current best demonstrated control technology, the fabric filter, is the same as that used when the standards were promulgated. No major improvements in this technology have occurred during the intervening period; however, one company has installed a proprietary wet scrubber, which appears to be almost as effective as a fabric filter and meets the standards.

Although the fabric filter technology has not changed, the effectiveness of pickup systems for various process and fugitive emissions has improved significantly.

Some EAF shops are now operating with closed roofs and a controlled fugitive emission pickup system in the roof to draw any indoor emissions into the control device. This system may utilize small openings in the ductwork to draw emissions slowly out of the roof area, or it may include dampers in the openings that can be opened or closed to remove these rooftop emissions. The roof emissions include charging and tapping emissions, and those that escape the direct furnace evacuation system and the canopy hoods above the furnace. The closed-roof and fugitive emission pickup system was designed to meet some local agencies no-visible-emission requirements from an EAF shop.

Other recent technology includes total enclosure of the furnace within the EAF building. The system is designed to capture all emissions of the furnace operation cycle (meltdown, charging, tapping, and slagging). Hoods are strategically located for capture of the charging, tapping, and slagging emissions. Additionally, during the charging operation, a curtain of air is blown across the roof opening to direct the emissions into the intake duct of the control device. This system theoretically prevents almost all emissions from escaping the enclosure and building.

Another new concept for containing emissions from the EAF is a partial enclosure around the furnace. The furnace itself may be equipped with the conventional direct shell evacuation and canopy hood system, but the partial enclosure around the furnace acts as a stack to direct fugitive furnace emissions upward into the emission capture system. Separate hoods are used to capture emissions during the tapping and slagging operation. The EAF

shop roof is closed and the area above the furnace and below the canopy hood must be kept clear so that the furnace can be charged normally by a crane. The partial enclosure is large enough to allow the furnace cover to be swung over the tapping area, where it can capture emissions from the ladle pouring spout and tapping hoods. This total system is reported to be virtually 100 percent effective in capturing all emissions from the furnace shop during normal operations.

Although about 30 furnaces were reported to have started operation from 1974 to 1979, only 5 commenced construction after the proposal of NSPS and therefore were subject to regulation. Only one of these five furnaces has been tested for visible emissions because the others have not completed their startup. Although the latter met the NSPS for visible emissions, the furnace shop did create an enforcement issue. The furnace shop has a closed roof; however, some visible emissions from charging or tapping operations drifted out the material access doors of the shop when they were open. Also, these charging and tapping emissions became intermingled and were emitted simultaneously due to other furnaces operating in the shop. The enforcement issue arose when it became unclear how to enforce NSPS when charging, tapping, and other shop emissions became mixed and escaped from the doors instead of the roof. These problems are expected to be recurring, as other new furnaces start operation and the NSPS may require further study to clarify the visible emission standard to cover this situation.

Four other recently constructed EAF's were required by local agencies to at least meet NSPS even though their construction started before NSPS proposal. One shop with two partially-enclosed furnaces using canopy hoods and sealed roof was tested for particulate and visible emissions. The local agency concluded that the system would meet NSPS based on their source tests. However, the control system uses a pressure baghouse, and the testing was conducted by company personnel in the presence of local agency observers. In tests of various compartments of the baghouse with a Hi-Vol sampler, the results show that the emissions ranged from 0.0097 mg/dscm (0.0000042 gr/dscf) to 0.08 mg/dscm (0.0000346 gr/dscf) during twelve 4- to 5-hour tests. However, this is not an official EPA testing method and further investigation by EPA will be necessary to substantiate this data.

The current standard does not cover several types of electric furnaces. The unregulated electric furnaces are: vaccum-arc remelting (VAR), vacuum induction melting (VIM), electro-slag remelting (ESR), and consumable electrode melting (CEM) which are primarily used to produce small tonnages of specialty steels. Investigation by EPA during this review revealed that the VAR, VIM, CEM, and ESR furnaces do not produce any significant emissions; therefore, they should not be considered for NSPS. Furthermore, these low polluting specialty furnaces are not capable of being replacements for the much larger conventional electric arc furnace which has a higher pollution potential.

Argon-oxygen decarbonization furnaces were found to be a highly significant emitter of particulate and visible emissions, and these furnaces are becoming an integral part of EAF shops that produce stainless steels. AOD furnaces are economical and flexible to operate; therefore, their use is expected to increase. Because AOD furnaces operate within an EAF shop, produce significant amounts of particulate and visible emissions, and use similar air pollution control devices, AOD furnaces should be included in the NSPS study for the EAF. One AOD furnace with canopy hood and baghouse was tested for particulate emissions. The average test result of 6.9 mg/dscm (0.0030 gr/dscf) for the AOD furnace is lower than the current EAF standard of 12 mg/dscm (0.0052 gr/dscf). Hence, the NSPS review for EAF should include AOD furnaces.

Conclusions

Based upon the review of the current NSPS previously summarized, a program to revise the standard is needed. This program, which is expected to begin in fiscal year 1980, will be directed toward:

1. Reviewing new particulate emission data based on the capabilities of the best available technology today. The investigation will include analysis of costs associated with this technology.
2. Reviewing new opacity data from recently designed efficient exhaust techniques, closed roofs for fugitive emissions, and improved hood collection for charging, tapping, and slagging emissions. These systems, where installed, appear to significantly reduced visible emissions from EAF shops.
3. Consideration of including the AOD furnace emissions in the revised EAF standard, or development of a separate standard for these furnaces. They are a highly visible source of particulate emissions.

All interested parties are invited to comment on this review, the conclusions, and EPA's planned course of action.

Dated April 11, 1980.

Douglas M. Costle,

Administrator.

[FR Doc. 80-11284 Filed 4-18-80; 8:45 am]

BILLING CODE 6560-01-M

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

ORGANIC SOLVENT CLEANERS

SUBPART JJ

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

FRL 1375-3]

Standards of Performance for New Stationary Sources Organic Solvent Cleaners

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule and notice of public hearing.

SUMMARY: The proposed standards would limit emissionsof volatile organic compounds (VOC) and trichloroethylene 1,1,1-trichloroethane, perchloroethylene, methylene chloride, and trichlorotrifluoroethane from new, modified, and reconstructed organic solvent cleaners (degreasers) in which solvents are used to clean (degrease) metal, plastic, fiberglass, or any other type of material. The proposed standards would specify several equipment designs and work practices for controlling emissions from cold cleaners, open top vapor degreasers, and conveyorized degreasers. When carbon adsorber control systems are used, a performance standard would also apply. To determine the emissions from carbon adsorbers, a new test method, Reference Method 23, is proposed to measure the concentration of the above mentioned halogenated compounds, and Reference Method 25 which was proposed on October 5, 1979 (44 FR 57792) would be used to measure emissions of VOC.

The proposed standards implement the Clean Air Act and are based on the Administrator's determination that organic solvent cleaners contribute significantly to air pollution. The intent is to require new, modified, and reconstructed organic solvent cleaners to use the best demonstrated system of continuous emission reduction, considering costs, nonair quality health, and environmental and energy impacts.

It is also proposed that standards be developed under section 111(d) of the Clean Air Act, as amended, for the control of emissions from existing facilities of the five halogenated organic solvents listed above. EPA is not committed to developing section 111(d) standards unless, after review of public comments, standards for one or more of these five solvents are promulgated for new, modified, or reconstructed facilities. If such standards were promulgated, EPA would develop a guideline document that would require States to develop emission control regulations for existing organic solvent cleaners which use any of the five halogenated solvents to which the promulgated regulations would apply.

A public hearing will be held to provide interested persons an opportunity for oral presentation of data, views, or arguments concerning the proposed standards.

DATES: *Comments.* Comments must be received on or before August 25, 1980.

Public Hearing. The public hearing will be held on July 24, 1980, beginning at 9:00 a.m.

Request to Speak at Hearing. Persons wishing to present oral testimony should contact EPA by July 17, 1980.

ADDRESSES: *Comments.* Comments should be submitted (in duplicate if possible) to the Central Docket Section (A-130), U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460, Attention: Docket No. OAQPS-78-12.

Public Hearing. The public hearing will be held at Research Triangle Park, North Carolina, in the EPA Environmental Research Center auditorium (Room B-102). Persons wishing to present oral testimony should notify Deanna Tilley, Standards Development Branch (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541-5421.

Background Information Document. The Background Information Document (BID) for the proposed standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to *Organic Solvent Cleaners—Background Information for Proposed Standards* (EPA-450/2-78-045a).

Docket. Docket number OAQPS-78-12, containing supporting information used by EPA in development of the proposed standards, is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Mr. John D. Crenshaw, Standards Development Branch, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5421.

SUPPLEMENTARY INFORMATION:

Proposed Standards

The proposed standards would limit the emissions of organic solvents from new, modified, and reconstructed degreasers in which solvents are used to clean and degrease metal, plastic, fiberglass, or any other type of material. Three types of degreasers would be regulated: cold cleaners, open top vapor degreasers, and conveyorized degreasers. The proposed regulations consist of a combination of design, equipment, work practice, and operational standards that allow for the best emission control and enforceability. Each type of degreaser would be required to have specific features for effectively reducing emissions. Pollution control devices for degreasers would include covers, raised freeboards, refrigerated freeboard devices and carbon adsorption systems. Work practices and operational procedures would also be required for each type of degreaser. These practices and procedures would assure the maximum effectiveness of a specific piece of control equipment, and would require use of techniques that reduce solvent emissions.

An inspection and maintenance program would also be required to prevent and correct solvent losses from leaks and equipment malfunctions. An operator training program is a proposed requirement because proper equipment operation and work practices play a significant role in effective control of solvent emissions from degreasers. Finally, owners and operators would be required to keep records on the amount and type of solvent purchased for a period of two years.

Summary of Environmental, Economic, and Energy Impacts

Environmental Impact. The proposed standards would reduce emissions of organic solvents (i.e., volatile organic compounds, trichloroethylene, 1,1,1-trichloroethane, perchloroethylene, methylene chloride, and trichlorotrifluoroethane) from all degreasing units for which construction was commenced after (date of proposal). Affected facilities that come on-line between 1980 and 1985 would emit an estimated 332,000 megagrams (366,000 tons) of organic solvents in 1985, if the degreaser units are uncontrolled. With implementation of the proposed regulations, controlled emissions from these facilities would be 120,000 megagrams (132,000 tons) in 1985, which constitutes a reduction of 64 percent.

The only potentially adverse impact on water quality of the proposed regulation would derive from the solvent dissolved in the steam condensate from regeneration (solvent desorption) of carbon adsorbers. Because the solubility of solvent in the condensate is very small, the amount of dissolved solvent is

slightly greater than one-tenth of one percent (0.1%) of the amount which would be discharged into the air if the proposed controls were not implemented. In a typical system, the carbon adsorber has a solvent capacity of 95 kilograms (210 pounds), and requires 3 kilograms (6.6 pounds) of steam to desorb each kilogram of solvent. Although desorption generates approximately 283 liters (10 cubic feet) of steam condensate per cycle, most solvent would be recovered by a water separator. Only 74 grams (0.16 pound) of solvent per day is expected to be lost in the waste stream from a typical carbon adsorber. The environmental impact of the disposal of this small amount of condensate is insignificant. Alternatives are under consideration by EPA for controlling the solvent in the effluent from desorption of a carbon adsorber. EPA may establish regulations pertaining to these effluents in the future.

The only solid waste impact due to implementation of the proposed standards would be disposal of the spent carbon from the carbon adsorbers used as air pollution control devices on certain types of degreasers. With replacement of spent carbon every 10 years, disposal of spent carbon from carbon adsorbers on affected facilities would amount to 243 megagrams (268 tons) nationwide starting in 1989 and would increase to 271 megagrams (299 tons) in 1995. Therefore, the solid waste impact from spent carbon would be minimal.

Economic Impact. The costs of compliance with the proposed standards are based on control equipment currently in use and commercially available. Economic analysis indicates that, under most conditions, the capital and annualized costs for the control equipment can be fully recovered by credits for the recovered solvent. Consequently, no adverse economic impact is anticipated to result from implementation of the proposed standards. The economic impact, may, in fact, be positive in the sense that net credits lead to lower production costs in most, if not all, industries. Methods to reduce solvent consumption and save money generally have not been accomplished in the past since degreasing costs generally average less than four-tenths of one percent of industry output.

Energy Impact. Energy consuming emission control devices for degreasing operations would include (1) refreigerated freeboard devices, (2) carbon adsorption systems, and (3) distillation equipment. Operation of these control devices in 1985 is estimated to require about 0.27 million kWh per day (equivalent to 440 barrels of oil per day); however, the proposed standards would result in the prevention or capture of degreaser emissions. Based upon the amount of energy that would have been required to manufacture replacement solvent, use of the required control devices on new organic solvent cleaners would conserve an estimated 3800 barrels of oil per day. Thus, the proposed standards in 1985 would result in a net conservation of energy equivalent to an estimated 3350 barrels of oil per day.

Rationale—Selection of Source for Control

Organic solvent cleaners (degreasers) have been identified as significant sources of air pollutant emissions which cause or contribute to the endangerment of the public health or welfare. Degreasing is not an industry but is an integral part of many manufacturing, repair, and maintenance operations. Volatile organic compounds, as well as 1,1,1-trichloroethane, trichlorotrifluoroethane, methylene chloride, trichlorethylene, and perchloroethylene constitute the emissions from organic solvent cleaners. There were an estimated 725,000 megagrams (800,000 tons) of organic solvents emitted from organic solvent cleaning operations in 1975. This represents about 4 percent of the total national volatile organic emissions from stationary sources, making organic solvent cleaners the fifth largest stationary source category for organic emissions. There are over 1,500,000 organic solvent cleaners currently in operation. If the current growth rate of 4.1 percent per year continues as expected, over 300,000 new organic solvent cleaners would be subject to these standards of performance by 1985.

Degreasing emissions include losses due to evaporation from the solvent bath, convection, carryout, leaks, and waste solvent disposal. Thus, the emissions from a degreaser are fugitive in nature. Many of the degreasers currently in use are operated without proper control emissions to the atmosphere. Emissions from degreasers may be controlled by the use of various equipment options (including a cover, extended freeboard, refrigerated freeboard device, and carbon adsorber) and specific work practices (involving parts handling, proper use and maintenance of equipment, preventing drafts, and controlling the rate of the degreasing operation).

Based on the large number of sources and their wide geographic distribution across the United States, the current sales and projected growth rate in the "industry" and the possible reduction in adverse environmental and health impacts which can be achieved, organic solvent cleaners have been selected for control through the development of standards of performance.

Selection of Affected Facilities

Organic solvent cleaning is not a specific industry but is an integral part of many manufacturing, repair, and maintenance operations. Practically every business that works metal or has maintenance or repair operations does some type of degreasing. Degreasing operations are often concentrated in urban areas where there are a large number of manufacturing facilities.

The solvents used in degreasing operations include halogenated hydrocarbons, petroleum distillates, ketones, ethers, and alcohols. These solvents are emitted as fugitive emissions from each of the three types of degreasers which would be regulated: (1) a cold cleaner, in which the article to be cleaned is immersed, sprayed or otherwise washed in a solvent at or about room temperature; (2) an open top vapor degreaser, in which the article is suspended in solvent vapor over a pool of boiling solvent and the solvent vapors condense on the article and dissolve or wash soil and grease from it; and (3) a conveyorized degreaser, in which articles are conveyed on a chain, belt or other conveying system either through a spray or pool of cold solvent, or through the vapor of a boiling solvent. In order to achieve significant reduction in volatile organic compound emissions from degreasing operations, all types of new, modified, or reconstructed degreasers would subject to control.

The mode of disposal of waste solvent can also contribute significantly to solvent emissions. In the past, disposal has generally been handled by the owners of organic solvent cleaners. If waste solvent disposal in 1985 were to follow the pattern of waste solvent disposal in 1974, about 43 percent of the waste solvent from new sources would be reclaimed, incinerated, landfilled and the remaining 57 percent could be an immediate source of air or water emissions.

A number of alternatives for regulating waste disposal have been considered. These include requiring incineration or reclamation, and establishment of standards under the Resource Conservation and Recovery Act (RCRA). Because of the impact on these small sources of requiring reclamation or incineration, regulation here is not now planned. Rather, the

Administrator is deferring at this time on waste disposal requirements and is pursuing this matter under RCRA. The section on waste disposal is being reserved, however, pending completion of the evaluation and resolution of the issues.

Selection of Pollutants and Regulatory Approach

Among the solvents used in degreasing operations, approximately 40 percent are non-halogenated hydrocarbons and 60 percent are halogenated hydrocarbons. Most of these solvents are also reactive volatile organic compounds (VOC), defined by this proposal as organic compounds which participate in atmospheric photochemical reactions or which may be measured by the applicable reference method specified under any subpart of 40 CFR Part 60. The proposed standards of performance apply to reactive VOC (ozone precursors) used as cleaning solvents and to five halogenated compounds for which there is a reasonable anticipation of public health endangerment.

Reactive Volatile Organic Compounds (VOC).

The proposed standards require control of any VOC demonstrated to be precursors to the formation of ozone and other photochemical oxidants in the atmosphere. While not all compounds are equally reactive, analysis of available data indicates that very few VOC are of such low photochemical reactivity that they can be ignored in oxidant control programs. EPA's "Recommended Policy on Control of Volatile Organic Compounds" (42 FR 35314; July 8, 1977) affirmed that many compounds which produced negligible oxidant concentrations during initial smog chamber tests were found to contribute appreciably to ozone levels when exposed to multiday irradiations in urban atmospheres. In those geographical areas where industrial and automotive emissions are subjected to long hours of sunlight, or where air stagnation occurs frequently, such low reactivity compounds may become significant source of photochemical oxidant.

EPA is developing standards of performance under section 111(b) for a number of categories of sources which emit these volatile organic compounds, which are ozone precursors. Ozone air pollution endangers the public health and welfare, as reflected in the Administrator's promulgation of a National Ambient Air Quality Standard for ozone (44 FR 8202; February 8, 1979). Emissions of ozone precursors from these source categories cause or contribute significantly to ozone air pollution. Trichloroethylene and, to a lesser extent, perchloroethylene react to form ozone and therefore would be subject to new source performance standards for reactive VOC.

The Administrator is also concerned about certain other possible health effects of perchloroethylene and trichloroethylene, apart from their role in ozone formation, and he believes that regulation of existing emission sources is necessary. Both substances have been found to induce a high incidence of hepatocellular carcinomas (liver tumors) in mice and have shown positive results in bacterial mutagencity assays (a screening technique for potential carcinogens). The Agency's initial evaluation of this information is that it presents "substantial evidence" (41 FR 21402; May 25, 1976) that both substances are human carcinogens. Consistent with EPA's proposed rules for regulating airborne carcinogens (44 FR 58642; October 10, 1979), if these initial evaluations are sustained after consideration of comments by EPA's Science Advisory Board, it is likely that perchloroethylene and trichloroethylene will be classified as high-probability carcinogens and, in light of the significant emissions of each, regulated as hazardous air pollutants under section 112 of the Act. This regulation would include both new and existing emission sources.

It is also possible that the Administrator will ultimately conclude that one or both of these chemicals is a moderate-probability carcinogen rather than a high-probability carcinogen. As the proposed airborne carcinogen rules explain, under the circumstances presented here, EPA could then "designate" the substance for regulation of existing organic solvent cleaners by the States under section 111(d) of the Clean Air Act. The Act provides for the designation of such substances for regulation under section 111(d) if the substances themselves have not been listed previously under section 108 or section 112. Because the evidence is clearly sufficient for the Administrator to conclude that both substances are at least moderate-probability carcinogens and that their emission by organic solvent cleaners causes air pollution which endangers public health and welfare, he is proposing designation of these two substances under section 111(d) at this time. Although a final determination by the Agency of the evidence of carcinogenicity would normally precede the selection of a regulatory alternative, the Administrator is proposing designation of perchloroethylene and trichloroethylene today for two reasons. First, this will put existing sources within the industry on notice that perchloroethylene and trichloroethylene would not be unregulated substitutes for the other three solvents for which designation is proposed today. Second, in the event that the Administrator ultimately concludes that perchloroethylene and trichloroethylene are moderate-probability rather than high-probability carcinogens, it will enable the section 111(d) process to proceed without delay as part of a coordinated regulatory program for the organic solvent cleaning industry. The Administrator intends to make a final carcinogenicity assessment for these two chemicals before promulgating today's proposals.

Negligibly Reactive Halogenated Compounds.

In addition to reactive halogenated compounds, the proposed new source regulations would apply to three additional halogenated solvents: 1,1,1-trichlorethane, methylene chloride, and trichlorotrifluoroethane. Since these chemicals are acknowledged by EPA to be negligibly reactive, they are not ozone precursors and must be designated under section 111(d) of the Act. As described above, the designation for the purpose of obtaining coverage under new source standards also requires the development under section 111(d) of standards for existing sources.

Both methylene chloride and 1,1,1-trichlorethane have scored positive as well as negative results in short-term mutagenicity and cell transformation tests. The weight of evidence has led the EPA Carcinogen Assessing Assessment Group to conclude in preliminary assessments that both chemicals exhibit suggestive evidence of human carcinogenicity. Under EPA's proposed airborne carcinogen policy, this finding would establish 1,1,1-trichlorethane and methylene chloride as candidates for regulation under section 111 as air pollutants "reasonably anticipated to endanger public health or welfare." In addition, trichlorotrifluoroethane and 1,1,1-trichlorethane have been implicated in the depletion of the stratospheric ozone layer, a region of the upper atmosphere which shields the earth from harmful wavelengths of ultraviolet radiation that increase skin cancer risks in humans.

The judgments of whether and to what extent 1,1,1-trichlorethane and methylene chloride are human carcinogens, and 1,1,1-trichlorethane and trichlorotrifluoroethane deplete the

ozone layer, are issues of considerable debate. While the scientific literature has been previously reviewed and summarized in the docket prepared for this rulemaking, more detailed health assessments are currently in preparation by EPA's Office of Research and Development. These assessments will be completed and submitted for external review, including review by the Science Advisory Board, prior to the promulgation of the regulations and the proposal of EPA guidance to States in developing existing source control measures. The extent to which the preliminary findings are affirmed by the review process may affect the final rulemaking for new as well as existing sources.

While the measure of concern is less for these latter three solvents than for perchloroethylene and trichloroethylene, the Administrator has chosen to proceed with the designation of 1,1,1-trichlorethane, methylene chloride, the trichlorotrifluoroethane at this time because emissions from these sources and the associated health risks can be reduced at a very low cost. This decision reflects EPA's concern that continued growth in uncontrolled emissions of 1,1,1-trichlorethane, methylene chloride, and trichlorotrifluoroethane from solvent cleaners may endanger public health, and is reinforced by projections that, were these chemicals exempted from regulation, the resulting substitution of exempt for non-exempt solvents could result in large increases in the emissions of these pollutants.

The designation of 1,1,1-trichlorethane, methylene chloride, and trichlorotrifluoroethane incorporates these chemicals under today's proposed new source standards and invokes section 111(d) which requires States to develop controls for existing sources. As described in detail below, the new source standards do not place unreasonable economic costs on the industry. While the impact of similar controls on existing sources could be more significant due to the technological problems associated with retrofit, this factor would be an important consideration in determining the appropriate control level for existing sources. In view of the substantial reduction in emissions which can be achieved at low cost, and the potential for substitution between these five compounds, the Administrator is persuaded that the present approach represents a prudent policy to protect public health. It should be emphasized that the health assessments discussed here are not final. The Administrator is aware of other relevant information that may become available. All applicable information will be carefully evaluated prior to making the final regulatory decision.

Summaries of the health basis for designating perchloroethylene, trichloroethylene, 1,1,1-trichloroethane, methylene chloride, and trichlorotrifluorethane are available in the public rulemaking docket described at the beginning of this notice.

Selection of Format for the Proposed Standards

Under the Clean Air Act, as amended, there are two regulatory alternatives available for establishing standards of performance for new stationary sources. Section 111(b) provides for establishing emission limitations or percentage reductions in emissions. However, when such standards are not feasible to prescribe or enforce, section 111(h) of the Clean Air Act provides that EPA may instead promulgate a design, equipment, work practice, or operational standard, or combination thereof. In either event, the standards prescribed would require new, modified, and reconstructed organic solvent cleaners to use the best demonstrated system of continuous emission reduction considering costs, nonair quality health and environmental impacts, and energy impacts. The emissions from organic solvent cleaners are unconfined (fugitive). Although techniques have been developed to measure the solvent lost from degreasing equipment (such as mounting entire organic solvent cleaners on scales), these methods are impractical for enforcement of regulations due to the length of time needed to accurately determine the solvent losses and because of the disruption this would cause in degreaser operations. For this reason, an equipment and work practice standard has been selected since it is not feasible to enforce emission limitations or percentage reductions in emissions for organic solvent cleaning operations.

Selection of the Best System of Emission Reduction

Emissions of volatile organic compounds from degreasers would be reduced significantly by the use of various pollution control devices, singly or in combination, as would be appropriate for each method of degreasing. These controls would include: cover, drain rack, raised freeboard, refrigerated freeboard device, downtime port covers, hanging flaps, and drying tunnel or lip exhaust in conjunction with a carbon adsorber. Degreaser emissions would be reduced further through the implementation of prescribed work practices. These work practices would include: closing the cover when work is not being lowered into or removed from the degreaser, storing solvent in covered containers, not exposing open degreasers to steady drafts with velocities exceeding 40m/min (131 ft/min), and not overloading the degreaser.

The best system of emission control for each type of degreaser was selected on the basis of EPA tests of the effectiveness of various controls used on degreasers operating under different conditions and using different solvents. These are described as follows:

Cold Cleaners.—The emission control system selected for cold cleaners (CC) would consist of both control equipment and a series of work practices. These controls used in combination would reduce solvent emissions from cold cleaners by about 80 percent. The equipment requirements would include a cover, a drain rack, and a visible fill line. The cover would be designed to be readily opened and closed at any time. External drain racks would lead the drainage back to the tank. If the CC is equipped with a parts basket, internal hooks to permit suspension of the basket above the solvent could be substituted for the drain rack. One of the work practices would require that the solvent level not exceed the visible internal maximum fill line. The proposed standards would require that the freeboard ratio for CC would be at least 0.7 if the solvent vapor pressure is greater than 4.3 kPa (33 mm Hg or 0.6 psi) measured at 38° C (100° F). The purpose for this is to prevent excessive volatilization, i.e. vaporization. Higher freeboard ratios impede excess vaporization of highly volatile solvents under normal operating conditions. However, many solvents used in cold cleaning operations do not volatilize as rapidly as others. For solvents with a vapor pressure of less than or equal to 4.3 kPa measured at 38° C (100° F), the proposed standards would require a freeboard ratio of 0.5.

The economic analysis for this emission control system for cold cleaners was based on a typical unit. The uncontrolled cold cleaner was assumed to be uncovered all the time, whereas the controlled unit had a cover that was used all but 2 hours per working day (20 loads cleaned per day). Based on these assumptions, the cover would reduce emissions by 349 kilograms (769 pounds) per year at a savings of $69.80. The drain rack would reduce emissions by 36 kilograms (79 pounds) per year with a savings of $7.92.

Remote Reservoir Cold Cleaner.—The emission control system selected for remote reservoir cold cleaners (RRCC) is less stringent than that proposed for conventional cold cleaners. During non-use periods, the solvent is enclosed in a reservoir and not subject to evaporation loss to the atmosphere. While parts are being cleaned, solvent is pumpted through a sink-like work area which drains back into the enclosed contaier. Because the reservoir is remote from the work area, this type of organic solvent cleaner is not subject to the evaporation losses suffered by conventional cold cleaners. Therefore, the proposed standards for remote reservoir cold cleaners would not require closable covers, provided the solvent used has a vapor pressure of less than or equal to 4.3 kPa (33 mm Hg or 0.6 psi) measured at 38° C (100° F), but would require covers if the solvent volatility was greater than 4.3 kPa.

Open Top Vapor Degreaser.—The emission control systems would be required for all new, modified, or reconstructed open top vapor degreasers (OTVD) consists of covers, raised freebacks, and refrigerated freeboard devices or carbon adsorption systems. EPA and industry tests have shown that covers are the most effective control device in reducing solvent emissions during nonoperating conditions. Raised freeboards have also been show to be effective at reducing these emissions. By raising the freeboard ratio from 0.5 to 0.75, solvent emissions are generally reduced 25–30 percent during idling conditions. Emission reductions are less during actual operating conditions due to the transference of loads through vapor/air interface. Freeboard ratios larger than 0.75 may yield greater emission reductions, however, higher freeboards tend to icrease the difficulty of transferring loads into and out of the degreaser. The demonstrated ability of covers and raised freeboards to reduce solvent emissions, and the minimal cost of these two control devices have been the primary reasons for requiring the use of covers during nonoperating periods and freeboards ratios of at least 0.75 for all new, modified, and reconstructed open top vapor degreasers.

Emission tests have also shown that refrigerated freeboard devices and lip exhausts connected to carbon adsorbers are more effective at reducing solvent emissions than raised freeboards. During operating conditions, emission reductions as high as 65 percent have been demonstrated with the use of carbon adsorbers, while refrigerated freeboard devices have been demonstrated to reduce solvent emissions by at least 40 percent. A raised freeboard ratio of 1.0 has also shown promise (55 percent reduction), but its effectiveness under cross-draft conditions has not been adequately evaluated. It is expected that the cold air blanket produced by a refrigerated freeboard device would provide greater control of cross-draft induced vapor losses. For these reasons, all new, modified, and reconstructed OTVD with vapor/air interface areas greater than one square meter would be required to use refrigerated freeboard devices, or have lip exhausts connected to carbon adsorbers.

Reference Method 23, "Determination of Halogenated Organics from Stationary Sources," would be the required test method to measure emissions of the regulated halogenated compounds from carbon adsorbers. The principle of the method is an integrated bag sample of stack gas that is subjected to gas chromatographic analysis, using flame ionization detection. The range of this method is 0.1 to 200 ppm. The emission limitation proposed by these standards of performance would be 25 ppm of any regulated halogenated organic compound measured over the length of the carbon adsorber cycle, or for three hours, whichever is less. The Administrator specifically requests comments on this proposed test method and emission limitation.

A cut-off size of one square meter was determined to be the most effective for OTVD, taking into consideration the absolute reduction in solvent emissions and economic analyses. Although the capital expenditures for refrigerated freeboard devices are greater than for raised freeboards, solvent savings would completely offset the added capital expenditures, provided the degreasers were operated properly. However, for small OTVD (less than 1 m^2 in open top area), refrigerated freeboard devices would not be a cost-effective alternative. Taking into consideration the small reduction in solvent emissions and economics, small open top vapor degreasers would not be required to have refrigerated freeboard devices.

EPA realizes that refrigerated freeboard devices with sub-zero (0°C) refrigerant temperatures are patented. If any degreaser manufacturer is unable to demonstrate alternative methods of control, and certifies that the licensing terms for sub-zero refrigerated freeboard devices are unreasonable, relief under section 308 of the Clean Air Act, as amended can be sought.

Although the proposed standards require specific control technologies, they do not preclude the use of other control options which are demonstrated to be equally effective in reducing solvent emissions. After proposal of these regulations, any person may request an equivalency determination. EPA expects to approve other methods of continuous emission reduction when they have been demonstrated to be as effective in reducing emissions as refrigerated freeboard devices. The Administrator will also welcome any additional data and information concerning the control efficiencies of raised freeboards and refrigerated freeboard devices. Tests are currently being conducted to investigate the effectiveness of refrigerated freeboard devices and increased freeboard ratios under cross-draft conditions. Preliminary results of these tests have shown varying test results for different solvents. Because of possible variation in test outcomes, additional tests are planned. Tests are also being conducted to evaluate the effectiveness of automated covers which close after the workload enters the degreaser. These test results and any additional information and data submitted to EPA during the public comment period will be used to further evaluate the appropriateness of the proposed emission control options. Expansion or deletion of these options will be evaluated prior to promulgation. All information obtained during the course of this investigation and received during the public comment period would be placed in the docket for public review and considered by EPA before taking final action to promulgate standards for new, modified, and reconstructed degreasers.

Conveyorized Degreasers.—There are two major types of conveyorized degreasers: conveyorized vapor degreaser (CVD) and conveyorized cold cleaners (CCC). Conveyorized vapor degreasers use the vapors of boiling solvent to clean and degrease surfaces, while conveyorized cold cleaners use non-boiling solvent in the liquid phase to clean surfaces. The emission control system selected for conveyorized degreasers consists of both control equipment and a series of work practices. Using these controls in combination will reduce solvent emissions from conveyorized degreasers by 60 percent.

The two major emission control requirements for CVD are carbon adsorbers or refrigerated freeboard devices, provided the CVD is greater than 2 square meters (21.6 ft^2) in vapor/air interface area. This cutoff size was determined to be the most effective, taking into consideration the absolute

reduction in solvent emission and economic analyses. For larger crossrod and monorail CVD, carbon adsorbers produce greater emission reductions at higher savings than do refrigerated freeboard devices. For owners or operators of small crossrod and monorail degreasers, the capital costs of a carbon adsorber could be prohibitive. Because of this, a refrigerated freeboard device may be used instead of a carbon adsorber. As with OTVD, the type of conveyorized vapor degreaser, the type of work being processed, and ambient conditions would determine which emission control system should be used.

For conveyorized cold cleaners, the major emission control requirement would be a carbon adsorber, provided the CCC is greater than 2 square meters (21.6 ft^2) in solvent/air interface area. Like CVD, this cutoff was determined to be the most effective, taking into consideration the absolute reduction in solvent emissions and economic analyses. Refrigerated freeboard devices would not be an option for CCC since they are only effective in reducing emissions of warm solvent vapors.

Equivalent Systems of Emission Reduction

These standards of performance do not preclude the use of other degreaser emission control equipment or procedures of operation which can be demonstrated to be equivalent, in terms of reducing solvent emissions, to those prescribed in the proposed regulation. For determination of equivalency, any person may write the Administrator of EPA and request approval of a test plan for demonstrating equivalency. The test plan must propose the use of specific equipment, test procedures, a date, and a U.S. location at which the person making the request wishes to demonstrate equivalency. In order to determine equivalency, the Administrator must find a substantial likelihood that the control technology used in normal operations would produce equivalent emission reductions as the standards would require, at approximately the same or less economic, energy, or environmental cost. An alternate equipment design would not be considered equivalent to the proposed requirements if it placed a greater burden upon the personnel operating the degreaser to manually operate the emission capture device (e.g., use of an automated cover could potentially be found equivalent to use of refrigerated freeboard devices, but a manually operated cover would not qualify). Automated operation of the emission control system is required because manual operation would be burdensome due to the frequency with which work enters and exits open top vapor degreasers (cycle times of only 6 minutes are not unusual) and because enforcement of these standards would primarily depend upon equipment certifications. Although work practices could not be substituted for equipment design requirements, alternatives to the work practices contained in the proposed standards could also be included in an equivalency determination.

Selection of Enforcement Methods

More than 325,000 new degreasers are expected to be in operation by 1985. The large number of degreasers precludes the inspection of all units on a periodic basis. Therefore, enforcement must be achieved through a combination of degreaser manufacturer certifications and EPA random inspections. Because EPA cannot inspect all degreasers that will be in operation, adherence to the work practices will basically depend upon voluntary compliance. Although the work practices are important, the equipment design requirements will be the primary mechanism for ensuring the control of organic solvent emissions from degreasing operations. A random inspection program would be designed to inspect all degreaser design types produced, but would cover only a sample of shops using degreasing equipment. To facilitate this program, the primary reporting burden would be place upon the manufacturers of degreasing equipment.

Under section 111(a)(5) of the Clean Air Act, as amended, manufacturers of degreasers would be considered owners until the degreasers are sold. Thus, the original manufacturer of a newly constructed degreaser would be responsible for making the proposed reports. Section 114(a)(1) of the Act specifies that the Administrator can require owners or operators to report information to EPA as may be reasonably required. Manufacturers of cold cleaners, remote reservoir cold cleaners, open top vapor degreasers, and conveyorized degreasers would be required to notify the Administrator of the date construction began on a new degreaser, certain equipment features, and the name, date and location to whom the ownership of the degreaser was transferred. This information would be reported once for each degreaser constructed, modified, or reconstructed and the reports would be submitted each quarter. If any manufacturer or other owner or operator feels that the information to be submitted is proprietary in nature, a request for confidential treatment can be submitted with the report. On September 1, 1976, EPA promulgated regulations (40 CFR part 2) which govern the treatment of confidential business information, including that obtained under section 114 of the Clean Air Act.

Under certain circumstances, the operator of the degreaser rather than the original manufacturer would be responsible for making the report. This would occur when a modification or reconstruction to an existing degreaser was made by any person other than the original manufacturer or when any affected degreaser is resold.

Certification would be supplemented by an EPA inspection program of representative types of models of degreasers from owners and operators selected at random. This program would determine compliance with the design requirements for all new degreasing equipment, and would determine compliance with the work practice and operational requirements by a random sample of degreasing operations. Inspection would include a visual check of the operation and an examination of the methods of waste solvent disposal.

This method of enforcement has been selected as the best option considering the savings in time and money for effective enforcement. As mentioned previously, the large number of new sources expected within the next five years prohibits inspection of each unit. Effort has been made to reduce the proposed reporting and recordkeeping burdens to the minimum needed to administer an effective enforcement program. EPA also considered requiring each degreaser operator to report directly to EPA upon installation of a new degreaser and to periodically report work practice methods in use. However, the reporting requirements would have caused an excessive burden to be placed on each degreaser operator and would have caused the generation of a large number of reports. For these reasons, the proposed reporting requirements are minimized to include a one-time report per degreaser of a few basic items. In addition, spot checks of representative types and models of degreasers in operation were selected as the best available option. Operators of degreasing equipment would only be required to keep records of solvent usage and disposition and would not be required to make written reports. These records can be discarded after a two year period. To further reduce the impact of these requirements, operators of small cold cleaners (less than 1 m^2), such as are commonly used in gasoline service stations, would be exempt from any recordkeeping or reporting except

for maintaining a simple record of the disposition of waste solvent.

Public Hearing

A public hearing will be held to discuss these proposed standards in accordance with section 307(d)(5) of the Clean Air Act. Persons wishing to make oral presentations should contact EPA at the address given in the ADDRESSES Section of this preamble. Oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement with EPA before, during, or within 30 days after the hearing. Written statements should be addressed to the Central Docket Section (A-130), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, D.C. 20460, Attention: Docket No. OAQPS-78-12.

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460.

Docket

The docket is an organized and complete file of all the information submitted to or otherwise considered by EPA in the development of this proposed rulemaking. The principal purposes of the docket are: (1) to allow interested parties to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process, and (2) to serve as the record in case of judicial review [section 307(d)(7)].

Miscellaneous

As prescribed by section 111 of the Clean Air Act, as amended, establishment of standards of performance for organic solvent cleaners was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that these sources contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In accordance with section 117 of the Act, publication of this proposal was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies. The Administrator will welcome comments on all aspects of the proposed regulation, including economic and technological issues on the proposed test methods.

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect:

> ... application of the best technological system of contunuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [section 111(a)(1)].

Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act requires (or has the potential for requiring) the imposition of a more stringent emission standard in several situations.

For example, applicable costs do not necessarily play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources locating in nonattainment areas, i.e., those areas where statutorily-mandated health and welfare standards are being violated. In this respect, section 173 of the Act requires that new or modified sources constructed in an area which exceeds the National Ambient Air Quality Standard (NAAQS) must reduce emissions to the level which reflects the "lowest achievable emission rate" (LAER), as defined in section 171(3) for such category of source. The statute defines LAER as that rate of emissions based on the following, whichever is more stringent:

> (A) the most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or
>
> (B) the most stringent emission limitation which is achieved in practice by such class or category of source.

In no event can the emission rate exceed any applicable new source performance standard [section 171(3)].

A similar situation may arise under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require that certain sources [referred to in section 169(1)] employ "best available control technology" (BACT) as defined in section 169(3) for all pollutants regulated under the Act. Best available control technology must be determined on a case-by-case basis, taking energy, environmental and economic impacts and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the Act.

In all events, State implementation plans (SIP's) approved or promulgated under section 110 of the Act must provide for the attainment and maintenance of NAAQS designed to protect public health and welfare. For this purpose SIP's must in some cases require greater emission reduction than those required by standards of performance for new sources.

Finally, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

In order to prevent duplicative regulatory reuirements, and in order to avoid conflicts in standard setting, EPA has been in contact with representatives of the Interagency Regulatory Liaison Group (IRLG). This group, composed of members from EPA, the Occupational Safety and Health Administration (OSHA), the Food and Drug Administration (FDA), and the Consumer Product Safety Commission (CPSC) was formed in August, 1977, to ensure that the agencies work closely together in areas of common interest and responsibility. In particular, EPA has been in contact with OSHA to ensure that the requirements for the proposed standard do not conflict with OSHA's requirements for ventilation of open surface tank operations (29 CFR 1910.94).

Under EPA's sunset policy for reporting requirements in regulations, the reporting requirements in this regulation will automatically expire five years from the date of promulgation unless EPA takes affirmative action to extend them. To accomplish this, a provision automatically terminating the reporting requirements at that time will be included in the text of the final regulations.

EPA will review this regulation four years from the date of promulgation as required by the Clean Air Act. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, and improvements in emission control technology.

Section 317 of the Clean Air Act requires the Administrator to prepare an

economic impact assessment for any new source standard of performance promulgated under section 111(b) of the Act. An economic impact assessment was prepared for the proposed regulations and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the proposed standards to insure that the proposed standards would represent the best system of emission reduction considering costs. The economic impact assessment is included in the Background Information Document.

Dated: April 17, 1980.

Douglas M. Costle,

Administrator.

It is proposed to amend Part 60 of Chapter I, Title 40 of the Code of Federal Regulations as follows:

1. By adding alphabetically a definition of the term "volatile organic compound" to § 60.2 of Subpart A—General Provisions as follows:

§ 60.2 Definitions

* * * * *

"Volatile organic compound" means any organic compound which participates in atmospheric photochemical reactions or is measured by the applicable reference methods specified under any subpart.

2. By adding Subpart JJ as follows:

Subpart JJ—Standards of Performance for Organic Solvent Cleaners

Sec.

60.360 Application and designation of affected facility.
60.361 Definitions.
60.362 Standards for volatile organic compounds, trichloroethylene, 1,1,1-trichloroethane, perchloroethylene, methylene chloride, and trichlorotrifluoroethane.
60.363 Equivalent method of control.
60.364 Reporting and Recordkeeping.
60.365 Waste disposal. (reserved).
60.366 Test method.

Authority: Sec. 111, 301(a) of the Clean Air Act as amended [42 U.S.C. 7411, 7601(a)], and additional authority as noted below.

Subpart JJ—Standards of Performance for Organic Solvent Cleaners

§ 60.360 Applicability and designation of affected facility.

The provisions of this subpart are applicable to all organic solvent cleaners for which construction was commenced after (date of proposal) which are used for organic solvent cleaning (degreasing) of any materials.

§ 60.361 Definitions.

All terms used in this subpart, but not specifically defined in this Section shall have the meaning given them in the Act and in Subpart A of this part.

"Adsorption cycle" means a solvent recovery process which begins when solvent laden air is directed through an activated carbon bed, resulting in the capture of solvent vapors. An adsorption cycle shall be considered complete when the activated carbon bed becomes saturated with solvent, resulting in breakthrough of solvent vapors.

"Carbon adsorber" means a device in which an organic compound is brought into contact with activated carbon and is retained.

"Certification" means a written statement signed by the owner or operator of the affected facility.

"Cold cleaner" means any device or piece of equipment which contains and uses an organic solvent in the liquid phase to clean surfaces.

"Conveyorized cold cleaner" means any conveyorizer degreaser which uses an organic solvent in the liquid phase to clean surfaces.

"Conveyorized degreaser" means any device which uses an integral, continuous, mechanical system for moving materials or parts to be cleaned into and out of an organic solvent liquid or vapor cleaning zone.

"Conveyorized vapor degreaser" means any conveyorizer degreaser which uses an organic solvent in the vapor phase to clean surfaces.

"Drain rack" means any basket, tray, or sink located in, on, or exterior to a degreaser, which permits excess or condensed solvent to drain from the parts after degreasing and to return to the solvent bath.

"Drying tunnel" means an enclosed extension of the exit from a conveyorized degreaser.

"Equivalent method of control" means any method that can be demonstrated to the Administrator to provide at least the same degree of emission control as the specified control.

"Extended freeboard" means an addition to the sides of a degreaser to increase the freeboard height.

"Fill line" means a permanent mark in a degreaser tank that indicates the maximum operating liquid level recommended by the manufacturer.

"Freeboard height" means, for a cold cleaner, the distance from the liquid solvent level in the degreaser tank to the lip of the tank. For an open top vapor degreaser it is the distance from the solvent vapor level in the tank during idling to the lip of the tank. For a conveyorized cold cleaner it is the distance from the liquid solvent level to the bottom of the entrance or exit opening, whichever is lower. For a conveyorized vapor degreaser, it is the distance from the vapor level to the bottom of the entrance or exit opening, whichever is lower.

"Freeboard ratio" means a ratio of the freeboard height to the smaller interior dimension (length, width, or diameter) of the degreaser.

"Lip exhaust" means a device installed around the lip of a degreaser that draws in air and solvent vapor emissions and ducts them away from the degreaser area.

"Open top vapor degreaser" means any open top device or piece of equipment that contains and uses an organic solvent, at the boiling point of the solvent, and solvent vapor to clean equipment surfaces.

"Organic solvent" means any liquid substance which contains carbon and has the power to dissolve, causing solution.

"Organic solvent cleaner" or "degreaser" means any cold cleaner, remote reservoir cold cleaner, open top vapor degreaser, and conveyorized degreaser equipment and their ancillary components.

"Organic solvent cleaning" or "degreasing" means those processes using organic solvents to clean and remove soils from the surfaces of materials being processed.

"Refrigerated freeboard device" means a device which is mounted above the water jacket and the primary condenser coils, consisting of secondary coils which carry a refrigerant to provide a chilled air blanket above the solvent vapor to reduce emissions from the degreaser bath. The chilled air blanket temperature, measured at the centroid of the degreaser at the coldest point, shall be no greater than 30 percent of the solvent's boiling point (°F).

"Remote reservoir cold cleaner" means any device in which liquid solvent is pumped through a sink-like work area which drains back into an enclosed container while parts are being cleaned and in which the solvent in the enclosed container is not subject to evaporation losses to the atmosphere during non-use periods.

§ 60.362 Standards for volatile organic compounds, trichloroethylene, 1,1,1-trichloroethane, perchloroethylene, methylene chloride, and trichlorotrifluoroethane.

(a) Except as provided in paragraph (d) of this section, an owner or operator shall operate a cold cleaner, or a remote reservoir cold cleaner only if it has a cover that may be readily opened and

closed. A fusible link shall not interfere with cover operation.

(b) An owner or operator shall operate a cold cleaner only if it conforms to the following design requirements:

(1) A drain rack. If an external drain rack is used, it must allow the drained solvent to return to the solvent bath in the cold cleaner. If the cold cleaner is equipped with a parts basket, internal hooks to permit suspension of the basket above the solvent may be substituted for the drain rack.

(2) A freeboard ratio of at least 0.5. If the solvent used has a volatility greater than 4.3 kPa (33 mm Hg or 0.6 psi), measured at 38°C (100°F), the freeboard ration shall be at least 0.7.

(3) A visible fill line.

(c) Except as provided in paragraph (d) of this section, an owner or operator shall not operate a cold cleaner without meeting the following work and operational practices:

(1) The solvent level shall not exceed the fill line.

(2) When a flexible hose or flushing device is used, the pressure of solvent delivered by the pump may not exceed 69 kPa (10 psi), measured at the pump outlet, and the pumped solvent shall be delivered in a continuous stream and not a droplet spray. Flushing shall be performed only within the confines of the cold cleaner.

(3) When an air- or pump-agitated solvent bath is used, the agitator shall be operated so as to produce a rolling motion of the solvent but not observable splashing against tank walls or parts being cleaned.

(4) The cover shall be closed when the cold cleaner is not in use and when parts are being cleaned by solvent agitation.

(5) When the cover is open, the cold cleaner may not be exposed to drafts greater than 40 m/min (131 ft/min), as measured between 1 and 2 meters upwind and at the same elevation as the tank lip.

(6) Solvent cleaned parts shall be drained for 15 seconds or until dripping has stopped, whichever is longer. Parts having cavities or blind holes shall be tipped or rotated while draining.

(7) Waste solvent, still, and sump bottoms shall be collected and stored in closed containers. The closed containers may contain a device that would allow pressure relief, but would not allow liquid solvent to drain from the container prior to disposal.

(8) Each owner shall provide a permanent label for each cold cleaner which states the required work and operating practices. If the freeboard ratio on a cold cleaner is less than 0.7, the label shall state the types of solvents which may be used in the cold cleaner. Such solvents include xylenes, mineral spirits, stoddard solvents, or other solvents with a volatility less than or equal to 4.3 kPa. The label shall be placed near the front of the degreaser in full view of the degreaser operator and written in English, and any other language that may be necessary for comprehension by personnel operating the degreaser. The label must be kept visible and legible at all times. The plant owner or operator shall ensure that each person who operates a cold cleaner understands the instructions on the label.

(9) Spills during solvent transfer shall be wiped up immediately. The wipe rags shall be stored in covered containers.

(d)(1) An owner or operator who operates a remote reservoir cold cleaner which uses solvent with a volatility of less than or equal to 4.3 kPa (0.6 psi or 33 mm Hg) measured at 38°C (100°F), and which has a drain area less than 100 cm^2 (15.5 in^2) shall be subject to the provisions of paragraph (c)(2), (c)(5), (c)(6), (c)(7), (c)(8), and (c)(9).

(2) An owner or operator who operates a remote reservoir cold cleaner which uses solvent with a volatility greater than 4.3 kPa (0.6 psi or 33 mm Hg) measured at 38° C (100° F), or has a drain area greater than or equal to 100 cm^2 (15.5 in^2) shall be subject to the provisions of paragraphs (d)(1), (c)(4), and (a).

(e) An owner or operator shall operate an open top vapor degreaser only if it conforms to the following design requirements:

(1) Each open top vapor degreaser shall be equipped with a cover that may be readily opened or closed. If the open top vapor degreaser is equipped with a lip exhaust, the cover shall be located below the lip exhaust.

(2) Each open top vapor degreaser shall have a freeboard ratio of at least 0.75.

(3) Each open top vapor degreaser shall be equipped with the following devices:

(i) A device which shuts off sump heat if sump liquid solvent level drops down to the height of sump heater coils, and

(ii) A vapor level control device which shuts off sump heat if the vapor level rises above the height of the primary condenser.

(4) Each open top vapor degreaser greater than 1.0 square meter (10.8 ft^2) shall be equipped with one or more of the following equipment controls:

(i) A refrigerated freeboard device, or

(ii) A lip exhaust connected to a carbon adsorber. The concentration of organic solvent in the exhaust from this device shall not exceed 25 ppm of any regulated halogenated organic compound as measured by Method 23 for the length of the carbon adsorber cycle or three hours, whichever is less. If other volatile organic compounds are used, then the emissions shall not exceed an average of 25 ppm as carbon, measured by Method 25 for the length of the carbon adsorber cycle or three hours, whichever is less.

(f) An owner or operator shall not operate an open top vapor degreaser without meeting the following required work and operational practices:

(1) The cover shall be closed when parts are not being degreased.

(2) When the cover is open, the open top vapor degreaser shall not be exposed to drafts greater than 40 m/min (131 ft/min), as measured between 1 and 2 meters upwind and at the same elevation as the tank lip.

(3) For any open top vapor degreaser equipped with a lip exhaust, the exhaust shall be turned off when the degreaser is covered.

(4) Parts being degreased shall not occupy more than 50 percent of the vapor-air interface area.

(5) The vertical speed of a powered hoist, if one is used, shall not be more than 3.3 m/min (10.8 ft/min) when lowering and raising the parts.

(6) Spraying operations shall be done within the vapor layer.

(7) Work shall not be lifted from the vapor layer until condensation or dripping has stopped. Parts having cavities or blind holes shall be tipped or rotated before being raised from the vapor layer.

(8) During start up, the primary condenser and the refrigerated freeboard device, if one is used, shall be turned on before the sump heater. During shutdown, the sump heater shall be turned off, and the solvent vapor layer allowed to collapse before the condenser water and refrigerated freeboard device are turned off.

(9) Porous or absorbent material shall not be degreased in an open top vapor degreaser.

(10) A routine inspection and maintenance program shall be implemented to reduce or prevent solvent losses from dripping drain taps, cracked gaskets and malfunctioning equipment. Leaks must be repaired as soon as they are discovered.

(11) Waste solvent, still, and sump bottoms shall be collected and stored in closed containers. The closed containers may contain a device that would allow pressure relief, but would not allow liquid solvent to drain from the container prior to disposal.

(12) Each owner shall provide a permanent label for each open top vapor degreaser which states the required work and operating practices. The label shall be placed near the front of the degreaser in full view of the degreaser operator and written in English, and in any other language that may be necessary for comprehension by personnel operating the degreaser. The label must be kept visible and legible at all times. The plant owner or operator shall ensure that each person who operates a degreaser understands the instructions on the label.

(13) When sumps are drained, solvent shall be transferred using threaded or other leakproof couplings.

(14) The carbon absorber bed shall not be bypassed during desorption.

(g) An owner or operator subject to the provisions of this subpart shall operate a conveyorized degreaser only if it conforms to the following design requirements:

(1) Each conveyorized degreaser shall have a freeboard ratio of at least 0.75.

(2) Each conveyorized degreaser shall be equipped with a drying tunnel, a rotating (tumbling) basked, hanging flaps, or other device to prevent cleaned parts from carrying out solvent liquid or vapor. When a drying tunnel is used, the air which moves through the tunnel to enhance drying shall be exhausted to a carbon adsorber. The concentration of organic solvent in the exhaust from this device may not exceed 25 ppm of any regulated halogenated organic compound as measured by Method 23 for the length of the carbon adsorber cycle or three hours, whichever is less. If other volatile organic compounds are used, then the emissions shall not exceed an average of 25 ppm as carbon, measured by Method 25 for the length of the carbon adsorber cycle or three hours, whichever is less.

(3) Each conveyorized degreaser shall be equipped with downtime port covers at the entrance and exit openings.

(4) Each conveyorized cold cleaner with a solvent-air interface area of 2.0m² (21.6 ft_2) or greater shall be equipped with a carbon adsorber. The concentration of organic solvent in the exhaust from this device may not exceed 25 ppm of any regulated halogenated organic compound as measured by Method 23 for the length of the carbon adsorber cycle or three hours, whichever is less. If other volatile organic compounds are used, then the emissions shall not exceed an average of 25 ppm as carbon, measured by Method 25 for the length of the carbon adsorber cycle or three hours, whichever is less.

(5) Each conveyorized vapor degreaser with a solvent-air interface of 2.0m² (21.6 ft²) or greater shall be equipped with one or more of the following equipment controls:

(i) A refrigerated freeboard device, or

(ii) A carbon adsorber. The concentration of organic solvent in the exhaust from this device shall not exceed 25 ppm of any regulated halogenated organic compound as measured by Method 23 for the length of the carbon adsorber cycle or three hours, whichever is less. If other volatile organic compounds are used, then the emissions shall not exceed an average of 25 ppm as carbon, measured by Method 25 for the length of the carbon adsorber cycle or three hours, whichever is less.

(6) Each conveyorized vapor degreaser shall be equipped with the following devices:

(i) A device which shuts off sump heat if sump liquid level drops down to the height of sump heater coils, and

(ii) A vapor level control device which shuts off sump heat if the vapor level rises above the height of the primary condenser coils.

(7) Each owner shall provide a permanent label for each conveyorized degreaser which states the required work and operating practices. The label shall be placed near the front of the degreaser in full view of the degreaser operator and written in English and in any other language that may be necessary for comprehension by personnel operating the degreaser. The label must be kept visible and legible at all times. The plant owner or operator shall ensure that each person who operates a degreaser understands the instructions on the label.

(8) Waste solvent, still, and sump bottoms shall be collected and stored in closed containers. The closed containers may contain a device that would allow pressure relief, but would not allow liquid solvent to drain from the container prior to disposal.

(9) The carbon adsorber bed shall not be bypassed during desorption.

§ 60.363 Equivalent methods of control.

Upon written application, the Administrator may approve the use of equipment or procedures after they have been demonstrated to his satisfaction to be equivalent, in terms of reducing solvent emissions to the atmosphere, to those prescribed for compliance within a specified paragraph of this subpart. The application must contain a complete description of the proposed testing procedure and the date, time, and location scheduled for the equivalency demonstration.

§ 60.364 Reporting and recordkeeping.

(a) The owner or operator of any degreaser affected by this subpart shall furnish the Administrator with a single report for each degreaser. These reports shall be submitted each quarter for all degreasers which were newly constructed, modified, or reconstructed and which were placed in operation or for which ownership was transferred in the previous quarter. Each report shall contain written notification (certification) of the following:

(1) Date construction, modification, or reconstruction of each degreaser was commenced.

(2) Make and model of degreaser (including the serial number if applicable).

(3) Name, date, and location to whom the ownership of the degreaser was transferred.

(4) Dimensions of the solvent-air interface area and the freeboard ratio.

(5) Specify whether a refrigerated freeboard device or carbon adsorber has been installed (if applicable) and certify that the required controls (design parameters), under section 60.362, are part of the degreaser for which this notification is required.

(6) The name, title, and signature of the individual making the certification.

(b) Each owner or operator of an affected facility subject to the provisions of this subpart, except as provided in paragraph (c) of this section, shall maintain records for a period of 2 years of the following:

(1) The amount and date of each purchase of new solvent.

(2) The name and/or type of solvent purchased.

(3) The amount, date, and method of disposal for spent solvent, sump bottoms, and/or still bottoms, as applicable.

(c) Each owner or operator of a cold cleaner with a solvent-air interface area of less than 1.0 m² (10.8 ft²) is not subject to the requirements of paragraph (b) of this section, but is required to maintain for a period of 2 years a record of the method of waste solvent disposal.

(d) The reporting and recordkeeping requirements under this section will automatically expire 5 years from the date of promulgation of this regulation unless affirmative action to extend them is taken by EPA. (Section 114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 60.365 Waste disposal [Reserved]

§ 60.366 Test method.

(a) Reference Method 23 or 25 of Appendix A, as applicable, shall be used to determine compliance with the

requirements under § 60.382 when carbon adsorbers are used. The results shall be reported as ppm of organics (Method 23) or ppm or carbon (Method 25). Each performance test shall consist of 3 separate samples, and the arithmetic mean of the 3 samples shall be used to determine compliance.

(Section 114 of the Clean Air Act as amended (U.S.C. 7414))

3. Appendix A to part 60 is amended by adding reference method 23 as follows:

Appendix A—Reference Methods

* * * * *

Method 23. Determination of Halogenated Organics From Stationary Sources

Introduction

Performance of this method should not be attempted by persons unfamiliar with the operation of a gas chromatograph, nor by those who are unfamiliar with source sampling because knowledge beyond the scope of this presentation is required. Care must be exercised to prevent exposure of sampling personnel to hazardous emissions.

1. *Applicability and Principle*

1.1 Applicability. This method applies to the measurement of halogenated organics such as carbon tetracholoride, ethylene dichloride, perchloroethylene, trichloroethylene, Methylene chloride, 1,1,1-trichloroethane, and trichlorotrifluoroethane in stack gases from sources as specifiedd in the regulations. It does not apply when the halogenated organics are contained in particulate matter.

1.2 Principle. An integrated bag sample of stack gas containing one or more halogenated organics is subjected to gas chromatographic (GC) analysis, using a flame ionization detector (FID).

2. *Range and Sensitivity.* The range of this method is 0.1 to 200 ppm. The upper limit may be extended by extending the calibration range or by diluting the sample.

3. *Interferences.* The chromatograph column with the corresponding operating parameters herein described normally provides an adequate resolution of halogenated organics; however, resolution interferences may be encountered in some sources. Therefore, the chromatograph operator shall select the column best suited to his particular analysis problem, subject to the approval of the Administrator. Approval is automatic provided that confirming data are produced through an adequate supplemental analytical technique, e.g. analysis with a different column or GC/mass spectroscopy. This confirming data must be available for review by the Administrator.

4. *Apparatus.*

4.1 Sampling (see Figure 23-1). The sampling train consists of the following components:

4.1.1 Probe. Stainless steel, Pyrex* glass, or Teflon* tubing (as stack temperature permits), each equipped with a glass wool plug to remove particulate matter.

4.1.2 Sample Line. Teflon, 6.4-mm outside diameter, of sufficient length to connect probe to bag. Use a new unused piece for each series of bag samples that constitutes an emission test, and discard upon completion of the test.

4.1.3 Quick Connects. Stainless steel, male (2) and female (2), with ball checks (one pair without), located as shown in Figure 23-1.

4.1.4 Tedlar or Aluminized Mylar Bags. 100-liter capacity, to contain sample.

4.1.5 Bag Containers. Rigid leakproof containers for sample bags, with covering to protect contents from sunlight.

4.1.6 Needle Valve. To adjust sample flow rate.

4.1.7 Pump. Leak-free, with minimum of 2-liters/min capacity.

4.1.8 Charcoal Tube. To prevent admission of halogenated organics to the atmosphere in the vicinity of samplers.

4.1.9 Flow Meter. For observing sample flow rate; capable of measuring a flow range from 0.10 to 1.00 liter/min.

4.1.10 Connecting Tubing. Teflon, 6.4-mm outside diameter, to assemble sampling train (Figure 23-1).

4.2 Sample Recovery. Teflon tubing, 6.4-mm outside diameter, to connect bag to gas chromatograph sample loop is required for sample recovery. Use a new unused piece for each series of bag samples that constitutes an emission test and discard upon conclusion of analysis of those bags.

4.3. Analysis. The following equipment is needed:

4.3.1 Gas Chromatograph. With FID, potentiometric strip chart recorder, and 1.0- to 2.0-ml sampling loop in automatic sample valve. The chromatographic system shall be capable of producing a response to 0.1 ppm of the halogenated organic compound that is at least as great as the average noise level. (Response is measured from the average value of the baseline to the maximum of the waveform, while standard operating conditions are in use.)

4.3.2 Chromatographic Column. Stainless steel, 3.05 m by 3.2 mm, containing 20 percent SP-2100/0.1 percent Carbowax 1500 on 100/120 Supelcoport. The analyst may use other columns provided that the precision and accuracy of the analysis of standards are not impaired and he has available for review information conforming that there is adequate resolution of the halogenated organic compound peak. (Adequate resolution is defined as an area overlap of not more than 10 percent of the halogenated organic compound peak by an interferent peak. Calculation of area overlap is explained in Appendix E, Supplement A: "Determination of Adequate Chromatographic Peak Resolution."

4.3.3 Flow Meters (2). Rotameter type, 0-to-100-ml/min capacity.

4.3.4 Gas Regulators. For required gas cylinders.

4.3.5 Thermometer. Accurate to 1°C, to measure temperature of heated sample loop at time of sample injection.

4.3.6 Barometer. Accurate to 5 mm Hg, to measure atmospheric pressure around gas chromatograph during sample analysis.

4.3.7 Pump. Leak-free, with a minimum of 100-ml/min capacity.

4.3.8 Recorder. Strip chart type, optionally equipped with either disc or electronic integrator.

4.3.9 Planimeter. Optional, in place of disc or electronic integrator (4.3.8), to measure chromatograph peak areas.

4.4 Calibration. Sections 4.4.2 through 4.4.6 are for the optional procedure in Section 7.1.

4.4.1 Tubing. Teflon, 6.4-mm outside diameter, separate pieces marked for each calibration concentration.

4.4.2 Tedlar or Aluminized Mylar Bags. 50-liter capacity, with valve; separate bag marked for each calibration concentration.

4.4.3 Syringe. 25-μl, gas tight, individually calibrated, to dispense liquid halogenated organic solvent.

4.4.4 Syringe. 50-μl, gas tight, individually calibrated to dispense liquid halogenated organic solvent.

4.4.5 Dry Gas Meter, with Temperature and Pressure Gauges. Accurate to ±2 percent, to meter nitrogen in preparation of standard gas mixtures, calibrated at the flow rate used to prepare standards.

4.4.6 Midget Impinger/Hot Plate Assembly. To vaporize solvent.

5. *Reagents.* It is necessary that all reagents be of chromatographic grade.

5.1 Analysis. The following are needed for analysis:

5.1.1 Helium Gas or Nitrogen Gas. Zero grade, for chromatographic carrier gas.

5.1.2 Hydrogen Gas. Zero grade.

5.1.3 Oxygen Gas or Air. Zero grade, as required by the detector.

5.2 Calibration. Use one of the following options: either 5.2.1 and 5.2.2, or 5.2.3.

5.2.1 Halogenated Organic Compound, 99 Mol Percent Pure. Certified by the manufacturer to contain a minimum of 99 Mol percent of the particular halogenated organic compound; for use in the preparation of standard gas mixtures as described in Section 7.1.

5.2.2 Nitrogen Gas. Zero grade, for preparation of standard gas mixtures as described in Section 7.1.

5.2.3 Cylinder Standards (3). Gas mixture standards (200, 100, and 50 ppm of the halogenated organic compound of interest, in nitrogen) The tester may use these cylinder standards to directly prepare a chromatograph calibration curve as described in Section 7.2.2, if the following conditions are met: (a) The manufacturer certifies the gas composition with an accuracy of ±3 percent or better (see Section 5.2.3.1). (b) The manufacturer recommends a maximum shelf life over which the gas concentration does not change by greater than ±5 percent from the certified value. (c) The manufacturer affixes the date of gas cylinder preparation, certified concentration of the halogenated organic compound, and recommended maximum shelf life to the cylinder before shipment from the gas manufacturer to the buyer.

5.2.3.1 Cylinder Standards Certification. The manufacturer shall certify the concentration of the halogenated organic compound in nitrogen in each cylinder by (a) directly analyzing each cylinder and (b)

*Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency

calibrating his analytical procedure on the day of cylinder analysis. To calibrate his analytical procedure, the manufacturer shall use, as a minimum, a three-point calibration curve. It is recommended that the manufacturer maintain (1) a high-concentration calibration standard (between 200 and 400 ppm) to prepare his calibration curve by an appropriate dilution technique and (2) a low-concentration calibration standard (between 50 and 100 ppm) to verify the dilution technique used. If the difference between the apparent concentration read from the calibration curve and the true concentration assigned to the low-concentration calibration standard exceeds 5 percent of the true concentration, the manufacturer shall determine the source of error and correct it, then repeat the three-point calibration.

5.2.3.2 Verification of Manufacturer's Calibration Standards. Before using, the manufacturer shall verify each calibration standard by (a) comparing it to gas mixtures prepared (with 99 Mol percent of the halogenated organic compounds) in accordance with the procedure described in Section 7.1 or by (b) having it analyzed by the National Bureau of Standards, if such analysis is available. The agreement between the initially determined concentration value and the verification concentration value must be within ±5 percent. The manufacturer must reverify all calibration standards on a time interval consistent with the shelf life of the cylinder standards sold.

5.2.4 Audit Cylinder Standards (2). Gas mixture standards with concentrations known only to the person supervising the analysis samples. The audit cylinder standards shall be identically prepared as those in Section 5.2.3 (the halogenated organic compounds of interest, in nitrogen). The concentrations of the audit cylinders should be: one low-concentration cylinder in the range of 25 to 50 ppm, and one high-concentration cylinder in the range of 200 to 300 ppm. When available, the tester may obtain audit cylinders by contacting: Environmental Protection Agency, Environmental Monitoring and Support Laboratory, Quality Assurance Branch (MD-77), Research Triangle Park, North Carolina 27711. If audit cylinders are not available at the Environmental Protection Agency, the tester must secure an alternative source.

6. *Procedure*

6.1 Sampling. Assemble the sampling train as shown in Figure 23-1. Perform a bag leak check according to Section 7.3.2. Join the quick connects as illustrated, and determine that all connections between the bag and the probe are tight. Place the end of the probe at the centroid of the stack and start the pump with the needle valve adjusted to yield a flow that will more than half fill the bag in the specified sample period. After allowing sufficient time to purge the line several times, connect the vacuum line to the bag and evacuate the bag until the rotameter indicates no flow At all times, direct the gas exiting the rotameter away from sampling personnel.

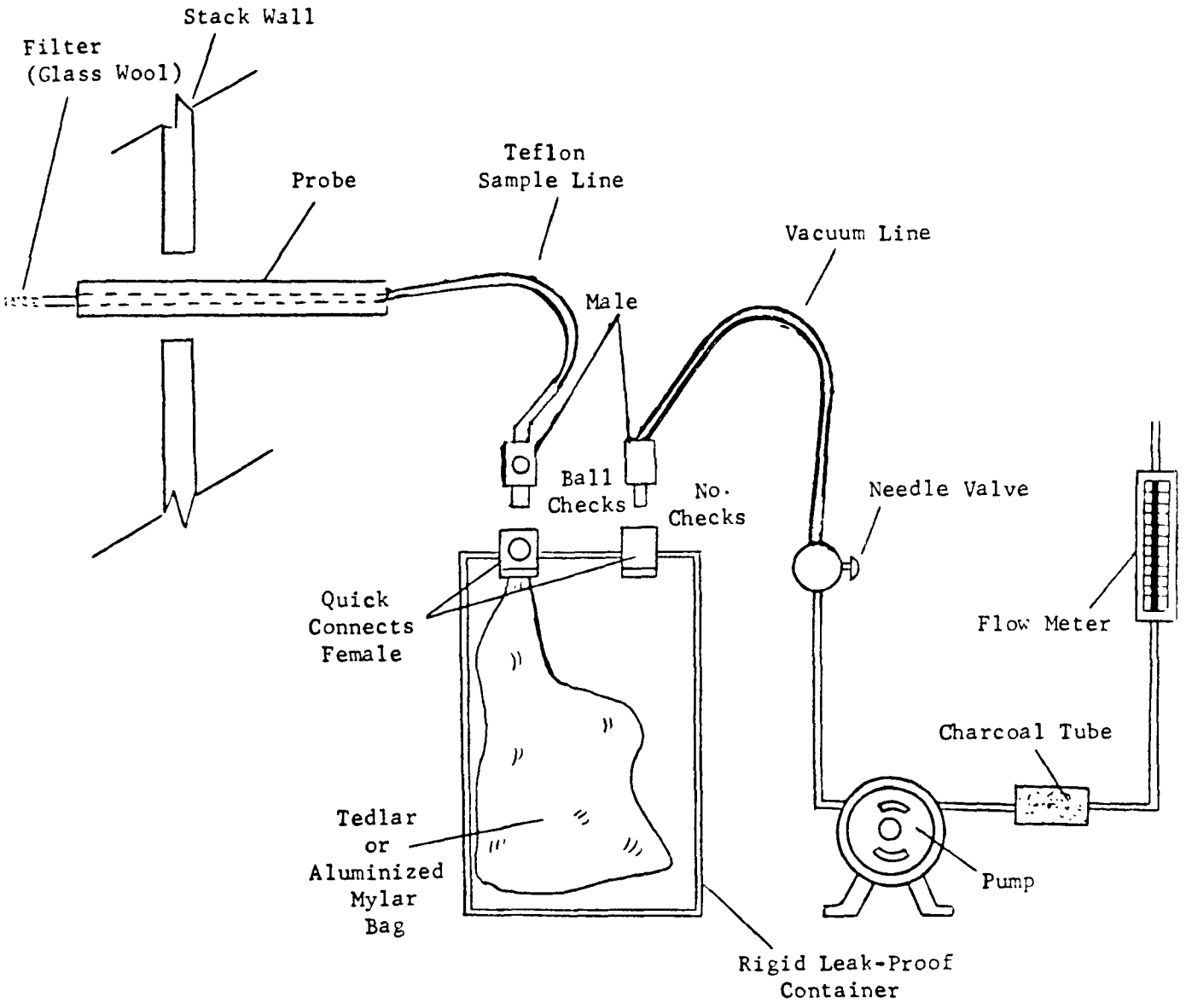


Figure 23-1. Integrated-bag sampling train. (Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.)

Then reposition the sample and vacuum lines and begin the actual sampling, keeping the rate constant. At the end of the sample period, shut off the pump, disconnect the sample line from the bag, and disconnect the vacuum line from the bag container. Protect bag container from sunlight.

6.2 Sample Storage. Keep the sample bags out of direct sunlight and protect from heat. Perform the analysis within 1 day of sample collection for methylene chloride, ethylene dichloride, and trichlorotrifluoroethane, and within 2 days for perchloroethylene, trichloroethylene, 1,1,1-trichloroethane, and carbon tetrachloride.

6.3 Sample Recovery. With a new piece of Teflon tubing identified for that bag, connect a bag inlet valve to the gas chromatograph sample valve. Switch the valve to receive gas from the bag through the sample loop. Arrange the equipment so the sample gas passes from the sample valve to a 0-to-100-ml/min rotameter with flow control valve followed by a charcoal tube and a 0-to1-in. H_2O pressure gauge. The tester may maintain the sample flow either by a vacuum pump or container pressurization if the collection bag remains in the rigid container. After sample loop purging is ceased, allow the pressure guage to return to zero before activating the gas sampling valve.

6.4 Analysis. Set the colum temperature to 100°C and the detector temperature to 225°C. When optimum hydrogen and oxygen flow rates have been determined, verify and maintain these flow rates during all chromatograph operations. Using zero helium or nitrogen as the carrier gas, establish a flow rate in the range consistent with the manufacturer's requirements for satisfactory detector operation. A flow rate of approximately 20 ml/min should produce adequate separations. Observe the base line periodically and determine that the noise level has stabilized and that base-line drift has ceased. Purge the sample loop for 30 sec at the rate of 100 ml/min, then activate the sample valve. Record the injection time (the position of the pen on the chart at the time of sample injection), the sample number, the sample loop temperature, the column temperature, carrier gas flow rate, chart speed, and the attenuator setting. Record the barometric pressure. From the chart, note the peak having the retention time corresponding to the halogenated organic compound, as determined in Section 7.2.1. Measure the halogenated organic compound peak area, A_m, by use of a disc integrator, electronic integrator, or a planimeter. Record A_m and the retention time. Repeat the injection at least two times or until two consective values for the total area of the peak do not vary more than 5 percent. Use the average value for these two total areas to compute the bag concentration.

6.5 Determination of Bag Water Vapor Content. Measure the ambient temperature and barometric pressure near the bag. From a water saturation vapor pressure table, determine and record the water vapor content of the bag as a decimal figure. (Assume the relative humidity to be 100 percent unless a lesser value is known.)

7. *Preparation of Standard Gas Mixtures, Calibration, and Quality Assurance.*

7.1 Preparation of Standard Gas Mixtures. (Optional procedure—delete if cylinder standards are used.) Assemble the apparatus shown in Figure 23-2. Check that all fittings are tight. Evacuate a 50-liter Tedlar or aluminized Mylar bag that has passed a leak check (described in Section 7.3.2) and meter in about 50 liters of nitrogen. Measure the barometric pressure, the relative pressure at the dry gas meter, and the temperature at the dry gas meter. Refer to Table 23-1. While the bag is filling, use the 50-μl syringe to inject through the septum on top of the impinger, the quantity required to yield a concentration of 200 ppm. In a like manner, use the 25-μl syringe to prepare bags having approximately 100- and 50-ppm concentrations. To calculate the specific concentrations, refer to Section 8.1. (Tedlar bag gas mixture standards or methylene chloride, ethylene dichloride, and trichlorotrifluoroethane may be used for 1 day, trichloroethylene and 1,1,1-trichloroethane for 2 days, and perchloroethylene and carbon tetrachloride for 10 days from the date of preparation. (Caution: If the new gas mixture standard is a lower concentration than the previous gas mixture standard, contamination may be a problem when a bag is reused.)

BILLING CODE 6560-01-M

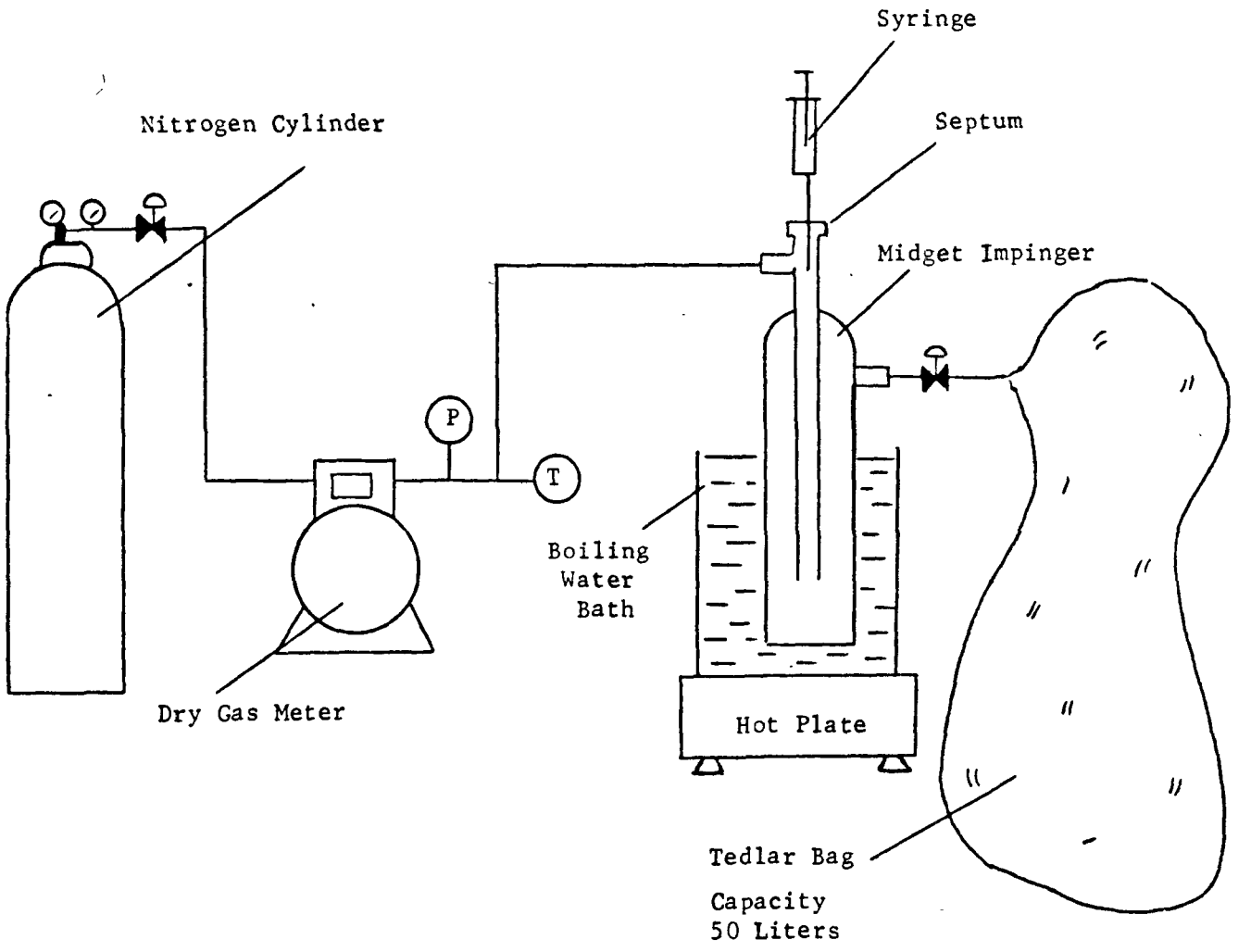


Figure 23-2. Preparation of Standards. (optional)

TABLE 23-1. INJECTION VALUES FOR PREPARATION OF STANDARDS (Optional, See Section 7.1)

Compound	Molecular Weight g/g-mole	Density at 293°K g/ml	µl/50 liters of N_2 required for approximate concentration of: 200 ppm	100 ppm	50 ppm
Perchloroethylene C_2Cl_4	165.85	1.6230	42.5	21.2	10.6
Trichloroethylene C_2HCl_3	131.40	1.4649	37.3	18.6	9.3
1,1,1-Trichloroethane $C_2H_3Cl_3$	133.42	1.4384	38.6	19.3	9.6
Methylene Chloride CH_2Cl_2	84.94	1.3255	26.6	13.3	6.7
Trichlorotrifluoroethane $C_2Cl_3F_3$	187.38	1.5790	49.3	24.7	12.3
Carbon Tetrachloride CCl_4	153.84	1.5940	40.1	20.1	10.0
Ethylene Dichloride $C_2H_4Cl_2$	98.96	1.2569	32.7	16.4	8.2

7 2 Calibration.

7.2.1 Determination of Halogenated Organic Compound Retention Time. (This section can be performed simultaneously with Section 7.2.2.) Establish chromatograph conditions identical with those in Section 6.4, above. Determine proper attenuator position. Flush the sampling loop with zero helium or nitrogen and activate the sample valve. Record the injection time, the sample loop temperature, the column temperature, the carrier gas flow rate, the chart speed, and the attenuator setting. Record peaks and detector responses that occur in the absence of the halogenated organic. Maintain conditions (with the equipment plumbing arranged identically to Section 6.3), flush the sample loop for 30 sec. at the rate of 100 ml/min with one of the halogenated organic compound calibration mixtures, and activate the sample valve. Record the injection time. Select the peak that corresponds to the halogenated organic compound. Measure the distance on the chart from the injection time to the time at which the peak maximum occurs. This distance divided by the chart speed is defined as the halogenated organic compound peak retention time. Since it is possible that there will be other organics present in the sample, it is very important that positive identification of the Halogenated organic compound peak be made.

7.2.2 Preparation of Chromatograph Calibration Curve. Make a gas chromatographic measurement of each Standard gas mixture (described in Section 5.2.3 or 7.1) using conditions identical with those listed in Sections 6.3 and 6.4. Flush the sampling loop for 30 sec at the rate of 100 ml/min with one of the standard gas mixtures and activate the sample valve. Record C_c, the concentration of halogenated organic injected, the attenuator setting, chart speed, peak area, sample loop temperature, column temperature, carrier gas flow rate, and retention time. Record the laboratory pressure. Calculate A_c, the peak area multipled by the attenuator setting. Repeat until two consecutive injection areas are within 5 percent, then plot the average of those two values versus C_c. When the other standard gas mixtures have been similarly analyzed and plotted, draw a straight line through the points derived by the least squares method. Perform calibration daily, or before and after each set of bag samples, whichever is more frequent.

7.3 Quality Assurance.

7.3.1 Analysis Audit. Immediately after the preparation of the calibration curve and prior to the sample analyses, perform the analysis audit described in Appendix E, Supplement B: "Procedure for Field Auditing GC Analysis."

7.3.2 Bag Leak Checks. While performance of this section is required subsequent to bag use, it is also advised that it be performed prior to bag use. After each use, make sure a bag did not develop leaks by connecting a water manometer and pressurizing the bag to 5 to 10 cm H_2O (2 to 4 in. H_2O). Allow to stand for 10 min. Any displacement in the water manometer indicates a leak. Also, check the rigid container for leaks in this manner. (Note: An alternative leak check method is to pressurize the bag to 5 to 10 cm H_2O (2 to 4 in. H_2O) and allow to stand overnight. A deflated bag indicates a leak.) For each sample bag in its rigid container, place a rotameter in line between the bag and the pump inlet. Evacuate the bag. Failure of the rotameter to register zero flow when the bag appears to be empty indicates a leak.

8. *Calculations.*

8.1 Optional Procedure Standards Concentrations. Calculate each halogenated organic standard concentration (C_c in ppm) prepared in accordance with Section 7.1 as follows:

BILLING CODE 6560-01-M

$$C_c = \frac{\frac{BD}{M}(24.055 \times 10^3)}{V_m Y \frac{293}{T_m}\frac{P_m}{760}} = 6.240 \times 10^4 \frac{BD\ T_m}{M\ V_m\ Y\ P_m}$$

Eq. 23-1

Where:

B = Volume of halogenated organic injected, µl.

D = Density of compound at 293°K, g/ml.

M = Molecular weight of compound, g/g-mole.

V_m = Gas volume measured by dry gas meter, liters.

Y = Dry gas meter calibration factor, dimensionless.

P_m = Absolute pressure of dry gas meter, mm Hg.

T_m = Absolute temperature of dry gas meter, °K.

24.055 = Ideal gas molal volume at 293° K and 760 mm Hg, liters/g-mole.

10^3 = Conversion factor. [(ppm)(ml)]/µl.

8.2 Sample Concentrations. From the calibration curve described in Section 7.2.2 above, select the value of C_c that corresponds to A_c. Calculate C_s, the concentration of halogenated organic in the sample (in ppm), as follows:

$$C_s = \frac{C_c P_r T_i}{P_i T_r (1-S_{wb})}$$

Eq. 23-2

Where:

C_c = Concentration of the halogenated organic indicated by the gas chromatograph, ppm.

P_r = Reference pressure, the laboratory pressure recorded during calibration, mm Hg.

T_i = Sample loop temperature at the time of analysis, °K.

P_i = Laboratory pressure at time of analysis, mm Hg.

T_r = Reference temperature, the sample loop temperature recorded during calibration, °K.

S_{wb} = Water vapor content of the bag sample, volume fraction.

9. *References.*

1. Fearheller, W. H., A. M. Kemmer, B. J. Warner, and D. Q. Douglas. Measurement of Gaseous Organic Compound Emissions by Gas Chromatography. EPA Contract No. 68-02-1404, Task 33 and 68-02-2818, Work Assignment 3. January 1978. Revised by EPA August 1978.

2. Supelico, Inc. Separation of Hydrocarbons. Bulletin 747. Belleforte, Pennsylvania. 1974.

3. Communication from Joseph E. Knoll. Percholoroethylene Analysis by Gas Chromatography. March 8, 1978.

4. Communication from Joseph E. Knoll. Test Method for Halogenated Hydrocarbons. December 20, 1978.

* * * * *

(Sections 111(b), 111(d), 114, and 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7414, and 7601(a)))

[FR Doc. 80-13044 Filed 6-10-80; 8:45 am]

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

LEAD-ACID BATTERY MANUFACTURE

SUBPART KK

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1315-4]

Standards of Performance for New Stationary Sources; Lead-Acid Battery Manufacture

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule and notice of public hearing.

SUMMARY: The proposed standards of performance would limit atmospheric emissions of lead from new, modified, and reconstructed facilities at lead-acid battery plants. This source was listed August 21, 1979 (44 FR 49222) in accordance with section 111(b)(1)(A) of the Clean Air Act as contributing significantly to air pollution, which may reasonably be anticipated to endanger public health or welfare. The intended effect of this proposal is to require new, modified, and reconstructed lead-acid battery manufacturing facilities to control lead emissions within the specified limits, which can be achieved through the use of the best demonstrated system of continuous emission reduction. A new reference method for determining compliance with lead standards is also proposed.

DATES: *Comments*—Comments must be received on or before March 14, 1980. *Public Hearing*—The public hearing will be held on Wednesday, February 13, 1980 beginning at 9:30 a.m. *Request to Speak at Hearing*—Persons wishing to present oral testimony must contact EPA by February 7, 1980.

ADDRESSES: *Comments*—Comments should be submitted (in duplicate if possible) to the Central Docket Section (A-130), U.S. Environmental Protection Agency, 401 M Street S.W., Washington, D.C. 20460, Attention: Docket No. OAQPS-79-1. *Public Hearing*—The public hearing will be held at EPA Environmental Research Center Auditorium, Rm B102, Research Triangle Park, N.C. 27711. Persons wishing to present oral testimony should notify Shirley Tabler, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541-5421. *Background Information Document*—The background information document for the proposed standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Specify "Lead-Acid Battery Manufacture, Background Information for Proposed Emission Standards" (EPA 450/3-79-028a). *Docket*—The docket, number OAQPS-79-1, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m. at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street S.W., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Proposed Standards

The proposed standards would limit atmospheric lead emissions from new, modified, or reconstructed facilities at any lead-acid battery manufacturing plant which has a production capacity equal to or greater than 500 batteries per day (bpd). The facilities which would be affected by the standards, and the proposed emission limits for these facilities are listed below:

Facility	*Lead emission limit*
Lead oxide production	5.0 mg/kg (0.010 lb/ton)
Grid casting	0.05 mg/m³ (0.2 x 10^{-4} gr/dscf)
Paste mixing	1.00 mg/m³ (4.4 x 10^{-4} gr/dscf)
Three-process operation	1.00 mg/m³ (4.4 x 10^{-4} gr/dscf)
Lead reclamation	2.00 mg/m³ (8.8 x 10^{-4} gr/dscf)
Other lead emitting operations	1.00 mg/m³ (4.4 x 10^{-4} gr/dscf)

The emission limit for lead oxide manufacture is expressed in terms of lead emissions per kilogram of lead processed, while those for other facilities are expressed in terms of lead concentrations in exhaust air.

A standard of 0 percent opacity is proposed for emissions from any of these facilities. The proposed standards would also require continuous monitoring of the pressure drop across the control system for any affected facility, to help insure proper operation of the system. Performance tests would be required to determine compliance with the proposed standards. A new reference method, Method 12, would be used to measure the amount of lead in exhaust gases, and Method 9 would be used to measure opacity. Process monitoring would be required during all tests.

Summary of Environmental, Energy, and Economic Impacts

There are approximately 190 lead-acid battery manufacturing plants in the United States, of which about 100 have been estimated to have capacities greater than or equal to 500 batteries per day (bpd). These plants are scattered throughout the country and are generally located in urban areas near the market for their batteries. Projections of the growth rate of the lead-acid battery manufacturing industry range from 3 to 5 percent per year over the next 5 years. Most of the projected increase in manufacturing capacity is expected to take place by the expansion of large plants (producing over 2000 batteries per day).

New, modified, and reconstructed facilities coming on-line over the next 5 years will emit about 95 Mg (104 tons) of lead to the atmosphere in the fifth year, if their emissions are controlled only to the extent required by current State particulate regulations. At some existing plants, emissions are controlled to a greater extent than State particulate regulations require. This practice might be continued at new plants in the absence of the proposed standards of performance. The proposed standards would reduce potential lead emissions from facilities coming on-line during the next 5 years to about 2.8 Mg (3.1 tons) in the fifth year. This is approximately 97 percent lower than the emission level which would be allowed under State particulate regulations. The proposed standards would also result in decreased nonlead particulate emissions from new plants, since equipment installed for the purpose of controlling lead-bearing particulate emissions would also control nonlead-bearing particulate emissions.

The results of dispersion modeling calculations indicate that the ambient impact of lead emissions from a new plant complying with the proposed standards would be less than the national ambient air quality standard for lead of 1.5$\mu g/m^3$ (averaged over calendar quarter). This is an important consideration, since most lead-acid battery plants are located in urban areas. Results of EPA dispersion modeling calculations indicate that the ambient lead standard will not be met in the vicinities of plants controlling emissions only to the extent required by existing State regulations.

The impact of the proposed standards on the wastewater and solid waste emissions of a lead-acid battery plant would depend on the technique used by that plant to comply with the proposed standards. The best demonstrated system for reduction of lead emissions is the use of fabric filters. High energy impingement scrubbers could also be used, but would have higher energy requirements and operating costs than fabric filters. At plants using impingement scrubbing to control emissions, lead-bearing wastewater would be generated. This would be

treated along with other plant wastewater prior to being disposed from the plant. The fractional increase in the lead content of wastewater discharged from a plant using impingement scrubbing to control atmospheric lead emissions would be about 0.5 to 4.5 percent. At plants using fabric filtration to comply with the proposed standards, the captured pollutant would be reclaimed, and there would be no increase in wastewater or solid waste emissions due to the proposed standards.

The energy needed to operate control equipment required to meet the proposed standards at a new plant would be approximately 2 percent of the total energy needed to run the plant. The incremental energy demand resulting from the application of the proposed standards to the battery manufacturing facilities expected to come on-line over the next five years would be about 2.8 Gigawatt hours of electricity in the fifth year. Approximately 4.8 thousand barrels of oil would be required to generate this electricity.

The capital cost of the installed emission control equipment necessary to meet the proposed standards on all new facilities coming on-line nationwide during the first five years of the standards would be approximately $8.6 million. The total annualized cost of operating this equipment in the fifth year of the proposed standards would be about $4 million.

These costs and energy and environmental impacts are considered reasonable, and are not expected to prevent or hinder expansion of the lead-acid battery manufacturing industry. Economic analysis indicates that, for plants with capacities larger than or equal to 500 bpd, the costs attributable to the proposed standards could be passed on with little effect on sales. The average incremental cost associated with the proposed standard would be about 30¢ per battery. This is about 1.6 percent of the wholesale price of a battery.

Modification and Reconstruction of Existing Sources

In accordance with provisions applicable to all standards of performance, the proposed standards for the lead-acid battery manufacturing industry would apply to modified and reconstructed facilities, as well as to new facilities.

Under the modification provisions of 40 CFR 60.14, except in certain cases, an existing facility would be affected by the proposed standards if some physical or operational change is made to that facility which results in an increase in atmospheric lead emissions from that facility. Actions which would not be considered modifications, and thus would not cause an existing facility to become subject to the standards, regardless of any emission increase are:

1. Routine maintenance, repair, and replacement of components.
2. An increase in the production rate of a facility which is accomplished with an expenditure on the source containing the facility of less than 5.5 percent of the value of the facility. (This is the Internal Revenue Service annual asset guideline repair allowance for a facility at a lead-acid battery plant.)
3. An increase in the number of operating hours of a facility.
4. The use of an alternative raw material if the facility was designed to accommodate such material prior to this proposal.
5. The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.
6. The relocation or change in ownership of an existing facility.

Under the reconstruction provisions applicable to all standards of performance (40 CFR 60.15), an existing facility might become subject to the standards if its components were replaced to such an extent that the fixed capital cost of the new components exceeded 50 percent of the fixed capital cost that would be required to construct a comparable new facility. The standards would not apply, however, if the Administrator determined that it would not be technologically or economically feasible to meet the standards. Such determinations would be made on a case-by-case basis.

Rationale for the Proposed Standards—Selection of Source and Pollutant for Control

The manufacture of lead-acid batteries begins with the casting of lead grids and the production of lead oxide powder. The lead oxide powder is mixed with water and sulfuric acid to form a stiff paste, which is then pressed onto the lead grids. The pasted grids (plates) are cured, stacked, and connected (burned) into groups that form the individual elements of a lead-acid battery. The battery plates are converted to active electrodes by the formation process. In this process, the battery elements are immersed in dilute sulfuric acid, and direct current is passed between the plates to form active electrodes. Formation can take place either in an open acid bath (dry formation), or after the battery elements have been assembled into battery cases (wet formation). At some plants, scrap lead is recycled in a lead reclamation process.

Most of the operations discussed above are independent of one another. For instance, most small plants do not have lead oxide production or lead reclamation facilities, and some large companies sell lead oxide. However, stacking and burning of battery plates and assembly of elements into battery cases are generally accomplished in a single operation, called the three-process operation.

Most lead-acid battery plants are located near residential or urban areas. These plants emit lead-bearing particulate matter to the atmosphere. Sources of atmospheric lead emissions at lead-acid battery plants include lead oxide production, grid casting, paste mixing, three-process operation, and lead reclamation facilities. A National Ambient Air Quality Standard has been established for lead. The health and welfare effects of lead are presented in the document, "Air Quality Criteria for Lead" (EPA-600/8-77-017). Based on the results of EPA emission tests and the current required level of control, it is estimated that emissions from lead-acid battery plants could result in ambient lead concentrations which exceed the National Ambient Air Quality Standard. These emissions may reasonably be anticipated to endanger public health or welfare. Therefore, standards are proposed for lead emissions from lead-acid battery plants. Standards are not proposed for nonlead particulate emissions because such emissions are slight when compared with particulate emissions from other sources. Also, control of lead emissions would result in the reduction of other particulate emissions as well.

In addition to lead-bearing particulate matter, plants using dry formation techniques emit sulfuric acid mist. This mist results from the entrainment of sulfuric acid in hydrogen bubbles which are generated during the formation process. Wet formation usually takes place in covered battery cases. Therefore, acid mist emissions from wet formation are small.

Sulfuric acid mist has been previously determined to be a health related pollutant for the purposes of section 111(d) of the Clean Air Act. Therefore, the Administrator considered proposing standards for the lead-acid battery manufacturing industry which would limit acid mist emissions from the dry formation process. The setting of standards requiring control of acid mist emissions from new, modified, and

reconstructed formation facilities would require States to limit acid mist emissions from existing plants as well, under section 111(d).

EPA tests on dry formation at one plant indicate that the uncontrolled sulfuric acid mist emission rate from this facility is low (1.1 kg/1000 batteries). Dispersion modeling studies based on this emission rate indicate that the maximum ambient impact of sulfuric acid mist emissions from the dry formation process at a plant as large as 6500 batteries per day would be less than 1 $\mu g/m^3$ on an annual basis. Therefore, standards for acid mist are not being proposed at this time.

In contrast, two literature sources indicate that the acid mist emission rate from dry formation may be much higher (up to 19 k/1000 batteries) than the rate measured by EPA. However, EPA is unable to determine the reliability of the data contained in these sources because neither the test methods used nor the process operating conditions during testing are known. Therefore, although these sources indicate that acid mist emissions from the formation process may be significant, they do not provide a sufficient basis for an acid mist standard for the formation process.

It is of concern to the Administrator that the decision not to regulate acid mist emissions from formation is based on the results of tests at only one plant. The public is specifically invited to submit comments with supporting data on the issue of acid mist control. Based on the information received, EPA may take action regarding control of acid mist emissions from the formation process.

Applicability

The proposed standards of performance would apply to new, modified, or reconstructed facilities at any lead-acid battery plant that has the capacity to produce 500 or more batteries in a day (24 hours). Plants with capacities less than 500 bpd are exempted from the proposed standards for several reasons. First, projections of the economic impact of standards on existing small plants (100 and 250 bpd) undergoing reconstruction or modification indicated that standards would have a severe negative impact on such plants. Also, although almost 50 percent of the lead-acid battery plants in the United States produce fewer than 500 bpd, these plants account for only about 2 percent of total lead-acid battery production. Finally, industry representatives do not forecast construction or expansion of small plants. In fact there has been a trend in recent years of small plants closing due to unprofitability. Increased demand for batteries in the future is expected to be accommodated by expansion of existing plants producing over 2000 bpd.

Selection of Affected Facilities

Lead emitting process operations selected as affected facilities are lead oxide production, grid casting, paste mixing, three-process operation, lead reclamation, and other lead emitting operations. These process operations often consist of several machines or production lines which perform the same function and which are located in the same area and ducted to the same control device. Therefore, for each of the process operations mentioned above, the affected facility is the entire operation. For example, at a plant with more than one three-process line, all of the lines together would be the affected facility.

Lead Oxide Manufacturing—In the lead-acid battery industry, lead oxide is produced either by the ball mill process, or by the Barton process. In the ball mill process, which is used more frequently, lead pigs or balls are tumbled in a mill, and the frictional heat generated by the tumbling action causes the formation of lead oxide. The lead oxide is removed from the mill by an air stream. In the Barton process, molten lead is atomized to form small droplets in an air stream. These droplets are then oxidized by the air around them.

Thus, in both the Barton process and the ball mill process, lead oxide product must be recovered from an air stream. In both processes, fabric filtration is used to accomplish this separation. It is estimated that lead emissions from a typical lead oxide manufacturing facility including product recovery are about 0.05 kg (0.116 lb) per 1,000 batteries, or about 10 g/Mg (0.02 lb/ton) of lead processed. Although these lead emissions are low, source tests have indicated that a well controlled lead oxide manufacturing facility would emit only about half as much lead as one designed only for economical recovery of lead oxide. Therefore, the lead oxide production process is designated an affected facility.

Grid Casting—Although lead emissions from grid casting are generally low, most grid casting work areas would be ventilated to comply with the in-plant OSHA lead concentration stanard of 50 $\mu g/m^3$. EPA tests detected an uncontrolled lead emission rate of 0.4 kg (0.9 lb) per 1,000 batteries (4.37 mg/m^3 or 19.1×10^{-4} gr/dscf of exhaust air), which was about 3.2 percent of the overall plant uncontrolled lead emission rate. Therefore, grid casting is designated an affected facility. The grid casting facility is defined to include both the grid casting machines, and the lead melting pots associated with these machines.

Paste Mixing—Paste mixing is generally a batch operation consisting of two phases: a charging phase, in which lead oxide is fed to the paste mixer, and a mixing phase, in which the lead oxide is mixed with water and sulfuric acid. Most emissions from paste mixing occur during the charging phase. However, lead emissions are also ducted from the paste mixer during the mixing phase. Uncontrolled lead emissions from paste mixing have been determined to be approximately 5.1 kg (11.2 lb) per 1,000 batteries (77.4 mg/m^3 or 338×10^{-4} gr/dscf of exhaust). This is about 40 percent of the total estimated uncontrolled lead emission rate for a lead-acid battery plant. The paste mixing facility is, therefore, selected as an affected facility.

Three-process Operation—The Three-process operation facility is defined to include all processes involved with plate stacking, burning, and assembly of elements into battery cases. Average uncontrolled lead emissions from three-process operations tested by EPA were 6.7 kg (14.7 lb) per 1,000 batteries (26 mg/m^3 or 115×10^{-4} gr/dscf of exhaust air). This is over 50 percent of the estimated lead emissions from a lead-acid battery plant. Therfore, the three-process operation is designated an affected facility.

Lead Reclamation—Lead reclamation is often a sporadic operation, on stream only when large quantities of defective small parts, grids, and plates are available. EPA measured lead emissions from this process to be 0.35 kg (0.77 lb) per 1000 batteries, 3.0 kg/Mg (5.9 lb/ton) of lead charged, or 227 mg/m^3 (990×10^{-4} gr/dscf) of exhaust air. Lead emissions can be very high during operation. For example, a 4000-bpd plant at which the lead reclamation facility is run for an 8-hour shift every 2 weeks would emit approximately 1.7 kg/hr (3.8 lb/hr) during operation. This is comparable with the lead emission rate from the three-process operation at the same plant. Therefore, the Administrator designates lead reclamation as an affected facility. Reverberatory furnances which are used for lead reclamation but which are affected by standards of performance for secondary lead smelters (40 CFR 60.120), would not be affected under the proposed standards.

Other Lead-Emitting Operations—Any lead-acid battery plant facility from which lead emissions are collected and ducted to the atmosphere but which is not considered part of the lead oxide

production grid casting, paste mixing, three-process operation, or lead reclamation facilities is considered an "other lead emitting operation." An example is slitting, a process whereby lead grids, cast in doublets, are slit (with an enclosed saw) into separate plates. The Administrator has selected other lead emitting operations as affected facilities to ensure the control of lead emissions from these processes.

Selection of the Best System of Emissions Reduction Considering Costs

Section 111 of the Clean Air Act requires that standards of performance reflect the degree of emission control achievable through application of the best demonstrated technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact, and energy requirements) has been adequately demonstrated. The proposed standards were developed based on information derived from (1) available technical literature on the lead-acid battery manufacturing industry and applicable emission control technology, (2) technical studies performed for EPA by independent research organizations, (3) information obtained from the industry during visits to lead battery plants and meetings with various representatives of the industry, (4) comments and suggestions solicited from experts, and (5) results of emission measurements conducted by EPA.

Techniques currently used to control atmospheric lead emissions from facilities at lead-acid battery plants include fabric filtration and impingement scrubbing of exhaust gases. Low energy scubbers are currently used to control emissions entrained in hot gases, or in gases containing moisture or possible spark hazards. Fabric filters can be used to control all atmospheric lead emissions from lead-acid battery manufacturing, provided that proper maintenance procedures are followed and that necessary precautions are taken to prevent condensation or sparks when necessary. They are commonly used in other industries to control emissions from sources having similar moisure problems and spark problems.

Several emission control alternatives were studied in the development of the proposed standards. One of these alternatives consists of fabric filter control for all affected facilities. The others consist of fabric filter control for some affected facilities and low energy impingement scrubber control for other affected facilities. The alternative which would achieve the best degree of emission control is fabric filter control of atmospheric lead emissions from all affected facilities. The other alternatives make use of low energy scrubbers to varying extents, and represent varying degrees of emission reduction. Economic analysis has shown that, for plants with capacities greater than or equal to 500 batteries per day, none of the control alternatives which were studied would impose an unreasonable cost. Also, the cost of any alternative is not viewed as being detrimental to industry expansion.

The proposed standards are based on the control of all lead emissions from lead-acid battery plants by fabric filtration. This basis was chosen because fabric filters can achieve a better degree of emission reduction than low energy scrubbers at a reasonable cost.

The use of control techniques other than fabric filtration would not be precluded by the proposed standards. High energy impingement scrubbers could be used to meet the emission limits. However, these would have higher operating costs and energy requirements than fabric filters. Scrubbers would also generate lead contaminated water, which would probably require treatment prior to disposal.

Selection of the Format for the Proposed Standard

In general, lead-acid battery manufacturing facilities may be considered independent of one another in that there is no continuous flow of materials. Lead oxide production operations, grid casting operations, paste mixing operations, lead reclamation operations, and three-process operations are independent. Also, not all plants have lead reclamation and lead oxide production operations, and some plants sell lead oxide.

Because of the independent nature of the facilities, two different forms were chosen for the proposed standards. The format of the proposed standards applicable to grid casting, paste mixing, three-process operation, lead reclamation, and other lead-emitting operations, is a concentration standard. The format of the standard for lead oxide manufacturing is mass per unit of lead input.

A concentration standard is proposed for three-process facilities because emissions from these facilities depend more on number of plates processed and the method of burning than on the weight of material processed. Since emissions from grid casting, paste mixing, and lead reclamation are often controlled by the control device which controls three-process operation emissions, concentration standards are also proposed for these facilities. A mass per unit lead input standard is proposed for lead oxide production facilities because these facilities generally have different emission control devices from three-process operation facilities and because emissions from lead oxide production are generally proportional to lead input.

Selection of Emission Limits

The proposed limits for lead emissions from lead oxide production, grid casting, paste mixing, three-process operation, lead reclamation, and other lead emitting facilities are based on emissions levels attainable using fabric filtration. In the development of background data for the proposed standards, atmospheric lead emissions from facilities at four lead-acid battery plants were measured using the proposed Method 12. In a previous study, lead emissions from facilities at two lead-acid battery manufacturing plants and one lead oxide manufacturing plant were measured using a similar test method.

The emission limits for three-process operation facilities, lead oxide production facilities, and other lead emitting facilities are based on lead levels measured in exhausts from fabric filters controlling emissions from such facilities. Fabric filters are not currently used in the lead-acid battery industry to control emissions from grid casting or lead reclamation and are not generally used to control emissions from the mixing phase of paste mixing. The emission limits for grid casting, paste mixing, and lead reclamation are, therefore, based on lead levels found in uncontrolled emissions from such facilities, and on the demonstrated emission reduction capabilities of fabric filters.

Tests of controlled and uncontrolled emissions from three-process facilities controlled by fabric filters indicated fabric filter lead collection efficiencies of about 99 percent. This control efficiency is consistent with efficiencies achieved by well maintained fabric filters in other applications. Because particulate emissions from all lead emitting facilities at battery plants are similar in composition and particle size, the Administrator has determined that comparable collection efficiencies can be achieved for emissions from grid casting, paste mixing, and lead reclamation.

Lead Oxide Manufacturing—The proposed standard for lead oxide production is 5 milligrams of lead per kilogram of lead processed (10 lb/ton).

This limit is based on results of tests of emissions from a ball mill lead oxide production facility with a fabric filter control system. The tests showed an average controlled emission rate of 4.2 mg/Kg (8.4 lb/ton) for this facility. EPA has not conducted tests of emissions from a well controlled Barton process. However, in both the ball mill process and the Barton process, lead oxide product must be removed from an air stream. Also, EPA tests on a Barton process indicated that Barton and ball mill processes have similar air flow rates per unit production rate. Therefore, it has been determined that a similar level of emission control could be achieved for a Barton process as has been demonstrated for the ball mill process.

Grid Casting—Impingement scrubbing, rather than fabric filtration, is currently used in the lead-acid battery manufacturing industry to control emissions from grid casting. Emissions from grid casting facilities were measured at two plants. At one of these plants, grid casting emissions were controlled by an impingement scrubber. At the other, grid casting emissions were not controlled. The average lead concentration in exhaust from the uncontrolled facility was 4.37 mg/m^3 (19.1×10^{-4} gr/dscf). Average uncontrolled and controlled lead emissions from the scrubber controlled facility were 2.65 mg/m^3 (11.6×10^{-4} gr/dscf) and 0.32 mg/m^3 (1.4×10^{-4} gr/dscf), respectively. Thus the lead collection efficiency of the scrubber was about 90 percent.

Fabric filtration can be used to control these emissions if spark arresters are used and the exhaust gas is kept above the dew point. The lead standard for grid casting, 0.05 mg/m^3 (0.2×10^{-4} gr/dscf), is based on the exhaust concentration achievable using a fabric filter with about 99 percent collection efficiency to control emissions.

Paste Mixing—Lead emissions from a paste mixing facility equipped with an impingement scrubber were measured. Average uncontrolled and controlled lead concentrations from this facility were 77.4 mg/m^3 (338×10^{-4} gr/dscf) and 10.8 mg/m^3 (47.0×10^{-4} gr/dscf), respectively.

Fabric filtration is not generally used to control emissions from the entire paste mixing cycle because of the high moisture content of paste mixer exhaust during the mixing cycle. However, fabric filtration can be used to control emissions from the entire cycle if the exhaust gas is kept above the dew point. The proposed lead emission standard for paste mixing, 1 mg/m^3 (4.4×10^{-4} gr/dscf), is based on the level achievable using a fabric filter with about 99 percent collection efficiency for the entire cycle.

In developing data for the proposed standards, EPA conducted tests at a plant where paste mixing emissions were controlled by two separate systems. At this plant, paste mixing required a total of 21 to 24 minutes per batch. During the first 14 to 16 minutes of a cycle (the charging phase), exhaust from the paste mixer was ducted to a fabric filter which also controlled emissions from the grid slitting (separating) operation. During the remainder of the cycle (mixing), paste mixer exhaust was ducted to an impingement scrubber which also controlled emissions from the grid casting operation. Uncontrolled or controlled emissions for the paste mixer alone were not tested. The average concentration of lead in emissions from the fabric filtration system used to control charging emissions was 1.3 mg/m^3 (5.5×10^{-4} gr/dscf). The average lead content of exhaust from the scrubber used to control mixing emissions was 0.25 mg/m^3 (1.1×10^{-4} gr/dscf). The average lead concentration in controlled emissions from this facility was about 0.95 mg/m^3 (4.2×10^{-4} gr/dscf) which is slightly below the proposed emission limit of 1 mg/m^3 (4.4×10^{-4} gr/dscf). A lower average emission concentration could be achieved by using fabric filtration to control emissions from all phases of paste mixing.

Three-Process Operation—The proposed lead concentration limit for three-process operation emissions is 1 mg/m^3 (4.4×10^{-4} gr/dscf). This limit is based on the results of EPA tests conducted at four plants where fabric filtration was used to control three-process operation emissions. All of these tests showed lead concentration below the proposed limit in controlled emissions from the three-process operation facilities.

Lead Reclamation—Lead emissions from a lead reclamation facility where emissions are controlled by an impingement scrubber were measured. The average lead concentrations in the inlet and outlet streams of the scrubber were 227 mg/m^3 (990×10^{-4} gr/dscf) and 3.7 mg/m^3 (16×10^{-4} gr/dscf), respectively. The collection efficiency of the scrubber was, therefore, about 98 percent.

Fabric filtration is not currently used to control emissions from lead reclamation facilities because of the high temperature of lead reclamation exhaust. However, fabric filters have been applied to hot exhaust systems at secondary lead smelters and in other industries. Therefore, the proposed standard for lead reclamation facilities of 2 mg/m^3 (8.8×10^{-4} gr/dscf), is based on the emission level attainable using a fabric filter with a collection efficiency of about 99 percent.

Other Lead Emitting Operations—Emissions from other lead emitting operations are generally collected and ducted to minimize worker exposure. These emissions are similar in composition and concentration to emissions from non-automated three-process operations. The proposed standard for other lead emitting operations is 1 mg/m^3 (4.4×10^{-4} gr/dscf) because lead emissions from those operations can be controlled to the same extent as lead emissions three-process operation facilities.

EPA measured emissions from a slitting facility, which would be classified as an "other lead emitting operation," controlled by a fabric filter. The controlled emissions from the facility had an average lead content of 0.938 mg/m^3 (4.1×10^{-4} gr/dscf), which is below the proposed concentration limit for other lead emitting operations.

Opacity Standards

A standard of 0 percent opacity is proposed for emissions from all affected facilities. Grid casting, paste mixing, three-process operation, and lead oxide manufacturing facilities were observed by EPA to have emissions with 0 percent opacity during observation periods of 7 hours and 16 minutes, 1 hour and 30 minutes, 3 hours and 51 minutes, and 3 hours and 19 minutes, respectively. Emissions ranging from 5 to 20 percent opacity were observed for a total of 11 minutes and 15 seconds during 3 hours and 22 minutes of observation at the lead reclamation operation source tested by EPA, which was controlled by a low-energy scrubber. However, the proposed standard is based on control of this process by a fabric filter, similar to three-process operations and paste mixers for which emissions with 0 percent opacity have been observed. A standard of 0 percent opacity is, therefore, also proposed for emissions from lead reclamation furnaces.

Under the proposed standards, opacity would be determined by taking the average opacity over a 6-minute period using EPA Test Method 9, and rounding the average to the nearest whole percentage. The rounding procedure is specified in the proposed standards in order to allow occasional brief emissions with opacities greater than 0 percent. When a fabric filter is used to control emissions, the outlet concentration from the filter may increase immediately after a component filter bag is cleaned. In the case of a

lead-acid battery plant, filter cleaning may result in occasional emissions with opacities greater than 0 percent. If the rounding off procedure were not specified, any reading of greater than 0 percent opacity during a 6-minute period could be considered as indicative of a violation of the proposed 0 percent opacity standard. However, the Administrator does not intend for occasional emissions greater than 0 percent opacity occurring during filter cleaning to be considered violations of the proposed standards. Therefore, the standards would specify that the average opacity be rounded to the nearest whole percentage. With this specification, 6-minute average opacities less than 0.5 percent would not be considered violations of the proposed standards. Emissions which result in 6-minute average opacities of 0.5 percent or greater are expected to be indicative of fabric filter malfunctions rather than filter cleaning emissions.

Testing and Recordkeeping

Performance tests would be required to determine compliance with the proposed standards. A new Reference Method 12 would be used to measure lead emissions. In addition, the following methods would be used to determine the necessary emission data: Method 1 for sample and velocity traverses, Method 2 for velocity and volumetric flow rate, Method 4 for stack gas moisture and Method 9 for stack opacity.

A measurement of the mass rate of feed would also be required during performance tests for lead oxide manufacturing because the units of the standards for this facility are milligrams of lead per kilogram of lead feed. Lead ingots of constant weight can be counted as they are fed to the lead oxide manufacturing process. The mass rate of feed measurements must be accurate within ±5 percent.

To determine compliance when two or more facilities at the same plant are ducted to a common control device, the exhaust rate from each source and the controlled lead concentrations must be measured. An equivalent standard for the applicable facilities is calculated by multiplying each applicable standard by the fractional exhaust flow rate of that facility and adding the numbers. This equivalent standard can then be compared with the measured concentration to determine compliance.

The proposed standards would require continuous monitoring of the pressure drop across the fabric filter or scrubber as applicable. A decrease in pressure drop of about 50 percent could indicate a decrease in lead removal efficiency because of either a fabric filter bag failure or a decrease in liquid-to-gas ratio.

EPA Reference Method 12 was developed to determine inorganic lead emissions from stationary sources. Particulate and gaseous lead emissions are withdrawn isokinetically from the source. The collected samples are then digested in acid solution and analyzed by atomic absorption spectrometry using an air acetylene flame. For a minimum analysis accuracy of ±10 percent, a minimum lead mass of 10μg should be collected. The typical sensitivities for a 1 percent change in absorption (0.0044 absorbance units) are 0.2 and 0.5 μg Pb/ml for the 217.0 and 283.3 nm lines, respectively.

The laboratory precision for Method 12, as measured by the coefficient of variation, was determined at a gray iron foundry, a lead battery manufacturing plant, a secondary lead smelter, and a lead recovery furnace at an alkyl lead manufacturing plant. The concentrations encountered during these tests ranged from 0.61 to 123.3 $\mu g/Pb/m^3$. The coefficient of variation for each run, which is the standard deviation of the run expressed as a percentage of the run mean concentration, ranged from 0.2 to 9.5 percent.

High copper concentrations may interfere with the analysis of lead at 217.0 nm. This interference can be avoided by analyzing the samples for lead using the 283.3 nm lead line. This problem should not occur, however, when analyzing samples from lead-acid battery facilities.

Records of performance tests and continuous monitoring system measurements would have to be retained for at least 2 years following the date of the measurements by owners and operators subject to this subpart. This requirement is included under § 60.7(d) of the general provisions of Part 60.

Public Hearing

A public hearing will be held to discuss these proposed standards in accordance with Section 307(d)(5) of the Clean Air Act. Persons wishing to make oral presentations should contact EPA at the address given in the ADDRESSES Section of this preamble. Oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement with EPA before, during, or within 30 days after the hearing. Written statements should be addressed to the Central Docket Section (A-130), U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460, Attention: Docket No. OAQPS-79-1.

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460.

Docket

The docket, containing all supporting information used by EPA to date, is available for inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, room 2903B, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460.

The docket is an organized and complete file of all the information submitted to or otherwise considered by EPA in the development of the rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development.

The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process. On judicial review, the record will consist of all materials in the docket except for certain interagency review materials (section 307(d)(7)(A) of the Act).

Miscellaneous

In accordance with section 117 of the Act, publication of these proposed standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies. The Administrator will welcome comments on all aspects of the proposed regulation, including economic and technological issues, and on the proposed test method.

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect:

> * * * application of the best adequately demonstrated technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact, and energy requirements) the Administrator determines has been adequately demonstrated [section 111(a)(1)].

Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance because of costs associated with its use. Accordingly, standards of performance should not be

viewed as the ultimate in achievable emission control. In fact, the Act requires (or has the potential for requiring) the imposition of a more stringent emission standard in several situations.

For example, applicable costs do not necessarily play as prominent a role in determining the "lowest achievable emissions rate" for new or modified sources located in nonattainment areas, i.e., those areas where statutorily mandated health and welfare standards are being violated.

In this respect, section 173 of the Act requires that a new or modified source constructed in an area that exceeds the National Ambient Air Quality Standards (NAAQS) must reduce emissions to the level which reflects the "lowest achievable emission rate" (LAER), as defined in section 171(3), for such category of source. The statute defines LAER as that rate of emissions based on the following, whichever is more stringent:

(A) the most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or

(B) the most stringent emission limitation which is achieved in practice by such class or category of source.

In no event can the emission rate exceed any applicable new source performance standard [section 171(3)].

A similar situation may arise under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require that certain sources [referred to in section 169(1)] employ "best available control technology" [as defined in section 169(3)] for all pollutants regulated under the Act. Best available control technology (BACT) must be determined on a case-by-case basis, taking energy, environmental and economic impacts, and other costs into account. In no event may the application of BACT result in emissions of any pollutants that will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the Act.

In all events, State Implementation Plans (SIP's) approved or promulgated under section 110 of the Act must provide for the attainment and maintenance of NAAQS designed to protect public health and welfare. For this purpose, SIP's must in some cases required greater emission reductions than those require by standards of performance of new sources.

Finally, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

EPA will review this regulation 4 years from the date of promulgation. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, and improvements in emission control technology.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance promulgated under section 111(b) of the Act. An economic impact assessment was prepared for the proposed regulations and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the proposed standards to insure that the proposed standards would represent the best system of emission reduction considering costs. The economic impact assessment is included in the background information document.

Dated: December 19, 1979.

Douglas M. Costle,

Administrator.

It is proposed that 40 CFR Part 60 be amended by adding a new Subpart KK and by adding a new reference method to Appendix A as follows:

1. A new subpart KK is added as follows:

Subpart KK—Standards of Performance for Lead-Acid Battery Manufacturing Plants

Sec.

60.370 Applicability and designation of affected facility.
60.371 Definitions.
60.372 Standards for lead.
60.373 Monitoring of emissions and operations.
60.374 Test methods and procedures.

Authority: Sec. 111, 301(a), Clean Air Act as amended [42 U.S.C. 7411, 7601(a)], and additional authority as noted below.

Subpart KK—Standards of Performance for Lead-Acid Battery Manufacturing Plants

§ 60.370 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the affected facilities listed in paragraph (b) of this section at any lead-acid battery manufacturing plant that has the capacity to produce 500 or more batteries per day (24 hours).

(b) The provisions of this subpart are applicable to the following affected facilities used in the manufacture of lead-acid storage batteries:

(1) Grid casting facility
(2) Paste mixing facility
(3) Three-process operation facility
(4) Lead oxide manufacturing facility
(5) Lead reclamation facility
(6) Other lead-emitting operations

§ 60.371 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Grid casting facility" means the facility which includes both lead melting pots and machines used for casting the grids used in battery manufacturing.

(b) "Lead-acid battery manufacturing plant" means any plant that produces a storage battery using lead and lead compounds for the plates and sulfuric acid for the electrolyte.

(c) "Lead oxide manufacturing facility" means the facility that produces lead oxide from lead, including product recovery.

(d) "Lead reclamation facility" means the facility that remelts lead scrap and casts it into lead ingots for use in the battery manufacturing process, and which is not a furnace affected under Subpart L of this part.

(e) "Other lead-emitting operation" means any lead-acid battery manufacturing plant operation from which lead emissions are collected and ducted to the atmosphere and which is not part of a grid casting, lead oxide manufacturing, lead reclamation, paste mixing, or three-process operation facility, or a furnace affected under Subpart L of this part.

(f) "Paste mixing facility" means the facility including charging and blending of the ingredients to produce a lead oxide paste.

(g) "Three-process operation facility" means the facility including those processes involved with plate stacking, burning or strap casting, and assembly of elements into the battery case.

§ 60.372 Standards for lead.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any grid casting facility any gases that contain lead in excess of 0.05 milligram of lead per dry standard cubic meter of exhaust (0.00002 gr/dscf).

(2) From any paste mixing facility any gases that contain in excess of 1.00 milligram of lead per dry standard cubic meter of exhaust (0.00044 gr/dscf).

(3) From any three-process operation facility any gases that contain in excess of 1.00 milligram of lead per dry standard cubic meter of exhaust (0.00044 gr/dscf).

(4) From any lead oxide manufacturing facility any gases that contain in excess of 5.0 milligrams of lead per kilogram of lead feed (0.010 lb/ton).

(5) From any lead reclamation facility any gases that contain in excess of 2.00 milligrams of lead per dry standard cubic meter of exhaust (0.00088 gr/dscf).

(6) From any other lead-emitting operation any gases that contain in excess of 1.00 milligram per dry standard cubic meter of exhaust (0.00044 gr/dscf).

(7) From any affected facility any gases with greater than 0 percent opacity (measured according to Method 9 and rounded to the nearest whole percentage).

(b) When two or more facilities at the same plant (except the lead oxide manufacturing facility) are ducted to a common control device, and equivalent standard for the total exhaust from the commonly controlled facilities shall be determined as follows:

$$S_e = \sum_{a=1}^{N} S_a(Q_{sd_a}/Q_{sd_T})$$

Where:

S_e is the equivalent standard for the total exhaust stream.

S_a is the actual standard for each exhaust stream ducted to the control device.

N is the total number of exhaust streams ducted to the control device.

Q_{sd_a} is the dry standard volumetric flow rate of the effluent gas stream from each facility ducted to the control device.

Q_{sd_T} is the total dry standard volumetric flow rate of all effluent gas streams ducted to the control device.

§ 60.373 Monitoring of emissions and operations.

The owner or operator of any lead-acid battery manufacturing plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a monitoring device(s) that continuously measures and permanently records the total pressure drop across the process emissions control system. The monitoring device shall have an accuracy of ±5 percent over its operating range.

(Section 114 of the Clean Air Act as amended (42 U.S.C. 7414))

§ 60.374 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided under § 60.8(b), shall be used to determine compliance according to § 60.8 as follows:

(1) Method 12 for the measurement of lead concentrations,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rate,

(4) Method 4 for stack gas moisture, and

(b) For Method 12, the sampling time for each run shall be at least 60 minutes except as provided for in paragraph (c), and the sampling rate shall be at least 0.85 dscm/h (0.53 dscf/min), except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) For grid casting, the sampling time for each Method 12 run shall be at least 180 minutes with a sampling rate of at least 0.85 dscm/h (0.53 dscf/min), except that shorter sampling times, when necessitated by process variables or other factors, may be approved by the Administrator.

(d) When different operations in a three-process operation facility are ducted to separate control devices, the lead emission concentration from the facility shall be determined using the equation:

$$C_{Pb_T} = \sum_{a=1}^{N} C_{Pb_a}(Q_{sd_a}/Q_{sd_T})$$

Where:

C_{Pb_T} is the lead emission concentration for the entire facility.

N is the number of control devices to which separate operations in the facility are ducted.

C_{Pb_a} is the emission concentration from each control device.

Q_{sd_a} is the dry standard volumetric flow rate of the effluent gas stream from each control device.

Q_{sd_T} is the total dry standard volumetric flow rate from all of the control devices.

(e) For lead oxide manufacturing facilities, the average lead feed rate to a facility, expressed in kilograms per hour, shall be determined for each test run as follows:

(1) Calculate the total amount of lead charged to the facility during the run by multiplying the number of lead pigs (ingots) charged during the run by the average mass of a pig in kilograms or by another suitable method.

(2) Divide the total amount of lead charged to the facility during the run by the duration of the run in hours.

(f) Lead emissions from lead oxide manufacturing facilities, expressed in milligrams per kilogram of lead charged, shall be determined using the following equation:

$$E_{Pb} = C_{Pb}Q_{sd}/F$$

Where:

E_{Pb} is the lead emission rate from the facility in milligrams per kilogram of lead charged.

C_{Pb} is the concentration of lead in the exhaust stream in milligrams per dry standard cubic meter as determined according to paragraph (a)(1) of this section.

Q_{sd} is the dry standard volumetric flow rate in dry standard cubic meters per hour as determined according to paragraph (a)(3) of this section.

F is the lead feed rate to the facility in kilograms per hours as determined according to paragraph (e) of this section.

(Section 114 of the Clean Air Act as amended (42 U.S.C. 7414))

2. Appendix A to Part 60 is amended by adding new Reference Method 12 as follows:

Appendix A—Reference Methods

* * * * *

Method 12. Determination of Inorganic Lead Emissions from Stationary Sources

1. Applicability and Principle

1.1 *Applicability.* This method applies to the determination of inorganic lead (Pb) emissions from specified stationary sources only.

1.2 *Principle.* Particulate and gaseous Pb emissions are withdrawn isokinetically from the source and collected on a filter and in dilute nitric acid. The collected samples are digested in acid solution and analyzed by atomic absorption spectrometry using an air acetylene flame.

2 Range, Sensitivity, Precision, and Interferences

2.1 *Range.* For a minimum analytical accuracy of ±10 percent, the lower limit of the range is 100 μg. The upper limit can be considerably extended by dilution.

2.2 *Analytical Sensitivity.* Typical sensitivities for a 1-percent change in absorption (0.0044 absorbance units) are 0.2 and 0.5 μg Pb/ml for the 217.0 and 283.3 nm lines, respectively.

2.3 *Precision.* The within-laboratory precision, as measured by the coefficient of variation ranges from 0.2 to 9.5 percent relative to a run-mean concentration. These values were based on tests conducted at a gray iron foundry, a lead storage battery manufacturing plant, a secondary lead smelter, and a lead recovery furnace of an alkyl lead manufacturing plant. The concentrations encountered during these tests ranged from 0.61 to 123.3 mg Pb/m³.

2.4 *Interferences.* Sample matrix effects may interfere with the analysis for Pb by flame atomic absorption. If this interference is suspected, the analyst may confirm the presence of these matrix effects and frequently eliminate the interference by using the Method of Standard Additions.

High concentrations of copper may interfere with the analysis of Pb at 217.0 nm. This interference can be avoided by analyzing the samples at 283.3 nm.

3. Apparatus

3.1 *Sampling Train.* A schematic of the sampling train is shown in Figure 12-1; it is similar to the Method 5 train. The sampling train consists of the following components:

3.1.1 *Probe Nozzle, Probe Liner, Pitot Tube, Differential Pressure Gauge, Filter Holder, Filter Heating System, Metering System, Barometer, and Gas Density Determination Equipment.* Same as Method 5, Sections 2.1.1 to 2.1.6 and 2.1.8 to 2.1.10, respectively.

3.1.2 *Impingers.* Four impingers connected in series with leak-free ground glass fittings or any similar leak-free noncontaminating fittings. For the first, third, and fourth impingers, use the Greenburg-Smith design, modified by replacing the tip with a 1.3 cm (½ in.) ID glass tube extending to about 1.3 cm (½ in.) from the bottom of the flask. For the second impinger, use the Greenburg-Smith design with the standard tip. Place a thermometer, capable of measuring temperature to within 1°C (2°F) at the outlet of the fourth impinger for monitoring purposes.

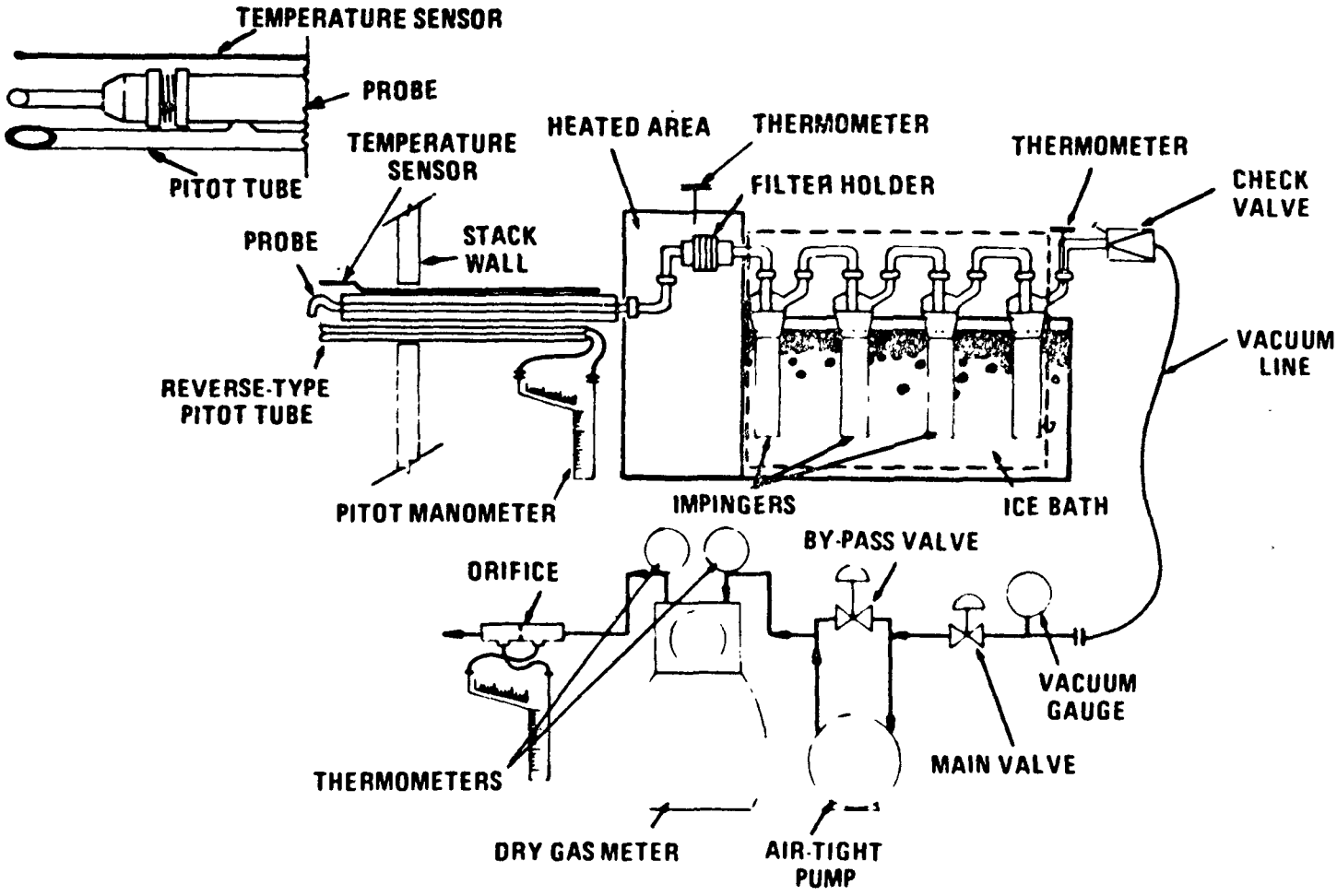


Figure 12-1. Inorganic lead sampling train.

3.2 *Sample Recovery.* The following items are needed:

3.2.1 *Probe-Liner and Probe-Nozzle Brushes, Petri Dishes, Plastic Storage Containers, and Funnel and Rubber Policeman.* Same as Method 5, Sections 2.2.1, 2.2.4, 2.2.6, and 2.2.7, respectively.

3.2.2 *Wash Bottles.* Glass (2).

3.2.3 *Sample Storage Container.* Chemically resistant, borosilicate glass bottles, for 0.1 N nitric acid (HNO_3) impinger and probe solutions and washes, 1000-ml. Use screw-cap liners that are either rubber-backed Teflon [1] or leak-free and resistant to chemical attack by 0.1 N HNO_3. (Narrow mouth glass bottles have been found to be less prone to leakage.)

3.2.4 *Graduated Cylinder and/or Balance.* To measure condensed water to within 2 ml or 1 g. Use a graduated cylinder that has a minimum capacity of 500 ml, and subdivisions no greater than 5 ml. (Most laboratory balances are capable of weighing to the nearest 0.5 g or less.)

3.2.5 *Funnel.* Glass, to aid in sample recovery.

3.3 Analysis. The following equipment is needed:

3.3.1 *Atomic Absorption Spectrophotometer.* With lead hollow cathode lamp and burner for air/acetylene flame.

3.3.2 Hot Plate.

3.3.3 *Erlenmeyer Flasks.* 1 25-ml, 24/40 $.

3.3.4 *Membrane Filters.* Millipore SCWPO 4700 or equivalent.

3.3.5 *Filtration Apparatus.* Millipore vacuum filtration unit, or equivalent, for use with the above membrane filter.

3.3.6 *Vomumetric Flasks.* 100-ml, 250-ml, and 1000-ml.

4. *Reagents*

4.1 Sampling. The reagents used in sampling are as follows:

4.1.1 Filter. Gelman Spectro Grade, Reeve Angel 934 AH, MSA 1106 BH, all with lot assay for Pb, or other high-purity glass fiber filters, without organic binder, exhibiting at least 99.95 percent efficiency (<0.05 percent penetration) on 0.3 micron dioctyl phthalate smoke particles. Conduct the filter efficiency test using ASTM Standard Method D 2986–71 or use test data from the supplier's quality control program.

4.1.2 *Silica Gel, Crushed Ice, and Stopcock Grease.* Same as Method 5, Section 3.1.2, 3.1.4, and 3.1.5, respectively.

4.1.3 *Water.* Deionized distilled, to conform to ASTM Specification D 1193–74, Type 3. If high concentrations of organic matter are not expected to be present, the analyst may delete the potassium permanganate test for oxidizable organic matter.

4.1.4 *Nitric Acid, 0.1 N. Dilute 6.5 ml of concentrated HNO_3 to liter 1 with deionized distilled water.* (It may be desirable to run blanks before field use to eliminate a high blank on test samples.)

4.2 *Pretest preparation.* 6 HNO_3 is needed. Dilute 390 ml of concentrated HNO_3 to 1 liter with deionized distilled water.

[1] Mention of trade names or specific products does not constitute endorsement by the U.S. Environmental Protection Agency.

4.3 *Sample Recovery.* 0.1 N HNO_3 (same as 4.1.4 above) is needed for sample recovery.

4.4 *Analysis.* The following reagents are needed for analysis (use ACS reagent grade chemicals or equivalent, unless otherwise specified):

4.4.1 *Water.* Same as 4.1.3 above.

4.4.2 *Nitric Acid.* Concentrated.

4.4.3 *Nitric Acid, 50 percent (V/V).* Dilute 500 ml of concentrated HNO_3 to 1 liter with deionized distilled water.

4.4.4 *Stock Lead Standard Solution, 1000 μg Pb/ml.* Dissolve 0.1598 g of lead nitrate [$Pb(NO_3)_2$] in about 60 ml of dionized distilled water, add 2 ml concentrated HNO_3, and dilute to 100 ml with deionized distilled water.

4.4.5 *Working Lead Standards.* Pipet 0.0, 1.0, 2.0, 3.0, 4.0, and 5.0 ml of the stock lead standard solution (4.4.4) into 250-ml volumetric flasks. Add 5 ml of concentrated HNO_3 to each flask and dilute to volume with deionized distilled water. These working standards contain 0.0, 4.0, 8.0, 12.0, 16.0, and 20.0 μg Pb/ml, respectively. Prepare, as needed, additional standards at other concentrations in a similar manner.

4.4.6 *Air.* Suitable quality for atomic absorption analysis.

4.4.7 *Acetylene.* Suitable quality for atomic absorption analysis.

4.4.8 *Hydrogen Peroxide, 3 percent (V/V).* Dilute 10 ml of 30 percent H_2O_2 to 100 ml with deionized distilled water.

5. Procedure

5.1 *Sampling.* The complexity of this method is such that, in order to obtain reliable results, testers should be trained and experienced with the test procedures.

5.1.1 *Pretest Preparation.* Follow the same general procedure given in Method 5, Section 4.1.1, except the filter need not be weighed.

5.1.2 *Preliminary Determinations.* Follow the same general procedure given in Method 5, Section 4.1.2.

5.1.3 *Preparation of Collection Train.* Follow the same general procedure given in Method 5, Section 4.1.3, except place 100 ml of 0.1 HNO_3 in each of the first two impingers, leave the third impinger empty, and transfer approximately 200 to 300 g of preweighed silica gel from its container to the fourth impinger. Set up the train as shown in Figure 12–1.

5.1.4 *Leak-Check Procedures.* Follow the general leak-check procedures given in Method 5, Sections 4.1.4.1 (Pretest Leak-Check), 4.1.4.2 (Leak-Checks During the Sample Run), and 4.1.4.3 (Post-Test Leak-Check).

5.1.5 *Sampling Train Operation.* Follow the same general procedure given in Method 5, Section 4.1.5. For each run, record the data required on a data sheet such as the one shown in EPA Method 5, Figure 5–2.

5.1.6 *Calculation of Percent Isokinetic.* Same as Method 5, Section 4.1.6.

5.2 *Sample Recovery.* Begin proper cleanup procedure as soon as the probe is removed from the stack at the end of the sampling period.

Allow the probe to cool. When it can be safety handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it. Do not cap off the probe tip tightly while the sampling train is cooling down as this would create a vacuum in the filter holder, thus drawing liquid from the impingers into the filter.

Before moving the sampling train to the cleanup site, remove the probe from the sampling train, wipe off the silicone grease, and cap the open outlet of the probe. Be careful not to lose any condensate that might be present. Wipe off the silicone grease from the glassware inlet where the probe was fastened and cap the inlet. Remove the umbilical cord from the last impinger and cap the impinger. The tester may use ground-glass stoppers, plastic caps, or serum caps to close these openings.

Transfer the probe and filter-impinger assembly to a cleanup area, which is clean and protected from the wind so that the chances of contaminating or losing the sample is minimized.

Inspect the train prior to and during disassembly and note any abnormal conditions. Treat the samples as follows:

5.2.1 *Container No. 1* (Filter). Carefully remove the filter from the filter holder and place it in its identified petri dish container. If it is necessary to fold the filter, do so such that the sample-exposed side is inside the fold. Carefully transfer to the petri dish any visible sample matter and/or filter fibers that adhere to the filter holder gasket by using a dry Nylon bristle brush and/or a sharp-edged blade. Seal the container.

5.2.2 *Container No. 2* (Probe). Taking care that dust on the outside of the probe or other exterior surfaces does not get into the sample, quantitatively recover sample matter or any condensate from the probe nozzle, probe fitting, probe liner, and front half of the filter holder by washing these components with 0.1 N HNO_3 and placing the wash into a glass sample storage container. Measure and record (to the nearest 2-ml) the total amount of 0.1 N HNO_3 used for each rinse. Perform the 0.1 N HNO_3 rinses as follows:

Carefully remove the probe nozzle and rinse the inside surfaces with 0.1 N HNO_3 from a wash bottle while brushing with a stainless steel, Nylon-bristle brush. Brush until the 0.1 N HNO_3 rinse shows no visible particles, then make a final rinse of the inside surface.

Brush and rinse with 0.1 N HNO_3 the inside parts of the Swagelok fitting in a similar way until no visible particles remain.

Rinse the probe liner with 0.1 N HNO_3. While rotating the probe so that all inside surfaces will be rinsed with 0.1 N HNO_3, tilt the probe and squirt 0.1 N HNO_3 into its upper end. Let the 0.1 N HNO_3 drain from the lower end into the sample container. The tester may use a glass funnel to aid in transferring liquid washes to the container. Follow the rinse with a probe brush. Hold the probe in an inclined position, squirt 0.1 N HNO_3 into the upper end of the probe as the probe brush is being pushed with a twisting action through the probe; hold the sample container underneath the lower end of the probe and catch any 0.1 N HNO_3 and sample matter that is brushed from the probe. Run the brush through the probe three times or more until no visible sample matter is carried out with the 0.1 N HNO_3 and none remains on the probe liner on visual inspection. With

stainless steel or other metal probes, run the brush through in the above prescribed manner at least six times, since metal probes have small crevices in which sample matter can be entrapped. Rinse the brush with 0.1 N HNO_3 and quantitatively collect these washings in the sample container. After the brushing make a final rinse of the probe as described above.

It is recommended that two people clean the probe to minimize loss of sample. Between sampling runs, keep brushes clean and protected from contamination.

After insuring that all joints are wiped clean of silicone grease, brush and rinse with 0.1 N HNO_3 the inside of the front half of the filter holder. Brush and rinse each surface three times or more, if needed, to remove visible sample matter. Make a final rinse of the brush and filter holder. After all 0.1 N HNO_3 washings and sample matter are collected in the sample container, tighten the lid on the sample container so that the fluid will not leak out when it is shipped to the laboratory. Mark the height of the fluid level to determine whether leakage occurs during transport. Label the container to clearly identify its contents.

5.2.3 *Container No. 3* (Silica Gel). Check the color of the indicating silica gel to determine if it has been completely spent and make a notation of its condition. Transfer the silica gel from the fourth impinger to the original container and seal. The tester may use a funnel to pour the silica gel and a rubber policeman to remove the silica gel from the impinger. It is not necessary to remove the small amount of particles that may adhere to the walls and are difficult to remove. Since the gain in weight is to be used for moisture calculations, do not use any water or other liquids to transfer the silica gel. If a balance is available in the field, the tester may follow procedure for Container No. 3 under Section 5.4 (Analysis).

5.2.4 *Container No. 4* (Impingers) Due to the large quantity of liquid involved, the tester may place the impinger solutions in several containers. Clean each of the first three impingers and connecting glassware in the following manner:

1. Wipe the impinger ball joints free of silicone grease and cap the joints.

2. Rotate and agitate each impinger, so that the impinger contents might serve as a rinse solution.

3. Transfer the contents of the impingers to a 500-ml graduated cylinder. Remove the outlet ball joint cap and drain the contents through this opening. Do not separate the impinger parts (inner and outer tubes) while transferring their contents to the cylinder. Measure the liquid volume to within ± 2 ml. Alternatively, determine the weight of the liquid to within ± 0.5 g. Record in the log the volume or weight of the liquid present, along with a notation of any color or film observed in the impinger catch. The liquid volume or weight is needed, along with the silica gel data, to calculate the stack gas moisture content (see Method 5, Figure 5-3).

4. Transfer the contents to Container No. 4.

5. Note: In steps 5 and 6 below, measure and record the total amount of 0.1 N HNO_3 used for rinsing. Pour approximately 30 ml of 0.1 N HNO_3 into each of the first three impingers and agitate the impingers. Drain the 0.1 N HNO_3 through the outlet arm of each impinger into Container No. 4. Repeat this operation a second time; inspect the impingers for any abnormal conditions.

6. Wipe the ball joints of the glassware connecting the impingers free of silicone grease and rinse each piece of glassware twice with 0.1 N HNO_3; transfer this rinse into Container No. 4. (*Do not rinse or brush the glass-fritted filter support.*) Mark the height of the fluid level to determine whether leakage occurs during transport. Label the container to clearly identify its contents.

5.2.5 Blanks. Save 200 ml of the 0.1 N HNO_3 used for sampling and cleanup as a blank. Take the solution directly from the bottle being used and place into a glass sample container labeled "0.1 N HNO_3 blank."

5.3 Sample Preparation.

5.3.1 *Container No. 1* (Filter). Cut the filter into strips and transfer the strips and all loose particulate matter into an 125-ml Erlenmeyer flask. Rinse the petri dish with 10 ml of 50 percent HNO_3 to insure a quantitative transfer and add to the flask. (Note. If the total volume required in Section 5.3.3 is expected to exceed 80 ml, use a 250-ml Erlenmeyer flask in place of the 125-ml flask.)

5.3.2 *Containers No. 2 and No. 4* (Probe and Impingers). (Check the liquid level in Containers No. 2 and/or No. 4 and confirm as to whether or not leakage occurred during transport; note observation on the analysis sheet. If a noticeable amount of leakage had occurred, either void the sample or take steps, subject to the approval of the Administrator, to adjust the final results.) Combine the contents of Containers No. 2 and No. 4 and take to dryness on a hot plate.

5.3.3 *Sample Extraction for Lead.* Based on the approximate stack gas particulate concentration and the total volume of stack gas sampled, estimate the total weight of particulate sample collected. Then transfer the residue from Containers No. 2 and No. 4 to the 125-ml Erlenmeyer flask that contains the filter using rubber policeman and 10 ml of 50 percent HNO_3 for every 100 mg of sample collected in the train or a minimum of 30 ml of 50 percent HNO_3, whichever is larger.

Place the Erlenmeyer flask on a hot plate and heat with periodic stirring for 30 min at a temperature just below boiling. If the sample volume falls below 15 ml, add more 50 percent HNO_3. Add 10 ml of 3 percent H_2O_2 and continue heating for 10 min. Add 50 ml of hot (80°C) deionized distilled water and heat for 20 min. Remove the flask from the hot plate and allow to cool. Filter the sample through a Millipore membrane filter or equivalent and transfer the filtrate to a 250-ml volumetric flask. Dilute to volume with deionized distilled water.

5.3.4 *Filter Blank.* Determine a filter blank using two filters from each lot of filters used in the sampling train. Cut each filter into strips and place each filter in a separate 125-ml Erlenmeyer flask. Add 15 ml of 50 percent HNO_3 and treat as described in Section 5.3.3 using 10 ml of 3 percent H_2O_2 and 50 ml of hot, deionized distilled water. Filter and dilute to a total volume of 100 ml using deionized distilled water.

5.3.5 *0.1 N HNO_3 Blank.* Take the entire 200 ml of 0.1 N HNO_3 to dryness on a steam bath, add 15 ml of 50 percent HNO_3, and treat as described in Section 5.3.3 using 10 ml of 3 percent H_2O_2 and 50 ml of hot, deionized distilled water. Dilute to a total volume of 100 ml using deionized distilled water.

5.4 Analysis.

5.4.1 *Lead Determination.* Calibrate the spectrophotometer as described in Section 6.2 and determine the absorbance for each source sample, the filter blank, and 0.1 N HNO_3 blank. Analyze each sample three times in this manner. Make appropriate dilutions, as required, to bring all sample Pb concentrations into the linear absorbance range of the spectrophotometer.

If the Pb concentration of a sample is at the low end of the calibration curve and high accuracy is required, the sample can be taken to dryness on a hot plate and the residue dissolved in the appropriate volume of water to bring it into the optimum range of the calibration curve.

5.4.2 *Mandatory Check for Matrix Effects on the Lead Results.* The analysis for Pb by atomic absorption is sensitive to the chemical composition and to the physical properties (viscosity, pH) of the sample (matrix effects). Since the Pb procedure described here will be applied to many different sources, many sample matrices will be encountered. Thus, check (mandatory) at least one sample from each source using the Method of Additions to ascertain that the chemical composition and physical properties of the sample did not cause erroneous analytical results.

Three acceptable "Method of Additions" procedures are described in the General Procedure Section of the Perkin Elmer Corporation Manual (see Citation 9.1). If the results of the Method of Additions procedure on the source sample do not agree within 5 percent of the value obtained by the conventional atomic absorption analysis, then the tester must reanalyze all samples from the source using the Method of Additions procedure.

5.4.3 *Container No. 3* (Silica Gel). The tester may conduct this step in the field. Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g; record this weight.

6. Calibration

Maintain a laboratory log of all calibrations.

6.1 *Sampling Train Calibration.* Calibrate the sampling train components according to the indicated sections of Method 5: Probe Nozzle (Section 5.1); Pitot Tube (Section 5.2); Metering System (Section 5.3); Probe Heater (Section 5.4); Temperature Gauges (Section 5.5); Leak-Check of the Metering System (Section 5.6); and Barometer (Section 5.7).

6.2 *Spectrophotometer.* Measure the absorbance of the standard solutions using the instrument settings recommended by the spectrophotometer manufacturer. Repeat until good agreement (± 3 percent) is obtained between two consecutive readings. Plot the absorbance (y-axis) versus concentration in μg Pb/ml (x-axis). Draw or compute a straight line through the linear portion of the curve. Do not force the calibration curve through zero, but if the curve does not pass through the origin or at least lie closer to the origin than ± 0.003

absorbance units, check for incorrectly prepared standards and for curvature in the calibration curve.

To determine stability of the calibration curve, run a blank and a standard after every five samples and recalibrate, as necessary.

7. Calculations

7.1 *Dry Gas Volume.* Using the data from this test, calculate $V_{m(std)}$, the total volume of dry gas metered corrected to standard conditions (20 °C and 760 mm Hg), by using Equation 5-1 of Method 5. If necessary, adjust $V_{m(std)}$ for leakages as outlined in Section 6.3 of Method 5. See the field data sheet for the average dry gas meter temperature and average orifice pressure drop.

7.2 *Volume of Water Vapor and Moisture Content.* Using data obtained in this test and Equations 5-2 and 5-3 of Method 5, calculate the volume of water vapor $V_{w(std)}$ and the moisture content B_{ws} of the stack gas.

7.3 *Total Lead in Source Sample.* For each source sample correct the average absorbance for the contribution of the filter blank and the 0.1 N HNO_3 blank. Use the calibration curve and this corrected absorbance to determine the μg Pb concentration in the sample aspirated into the spectrophotometer. Calculate the total Pb content C'_{Pb} (in μg) in the original source sample; correct for all the dilutions that were made to bring the Pb concentration of the sample into the linear range of the spectrophotometer.

7.4 *Lead Concentration.* Calculate the stack gas Pb concentration C_{Pb} in mg/dscm as follows:

$$C_{Pb} = K \frac{C'_{Pb}}{V_{m(std)}} \quad \text{Eq. 12-1}$$

Where:

K = 0.001 mg/μg for metric units.
= 2.205 lb/μg for English units.

7.5 *Isokinetic Variation and Acceptable Results.* Same as Method 5, Sections 6.11 and 6.12, respectively. To calculate v_s, the average stack gas velocity, use Equation 2-9 of Method 2 and the data from this field test.

8. Alternative Test Methods for Inorganic Lead

8.1 *Simultaneous Determination of Particulate and Lead Emissions.* The tester may use Method 5 to simultaneously determine Pb provided that (1) he uses 0.1 N HNO_3 in the impingers, (2) he uses a glass fiber filter with a low Pb background, and (3) he treats and analyzes the entire train contents, including the impingers, for Pb as described in Section 5 of this method.

8.2 *Filter Location.* The tester may use a filter between the third and fourth impinger provided that he includes the filter in the analysis for Pb.

8.3 *In-stack Filter.* The tester may use an in-stack filter provided that (1) he uses a glass-lined probe and at least two impingers, each containing 100 ml of 0.1 N HNO_3, after the in-stack filter and (2) he recovers and analyzes the probe and impinger contents for Pb.

9. Bibliography

9.1 *Perkin Elmer Corporation.* Analytical Methods for Atomic Absorption Spectrophotometry. Norwalk, Connecticut. September 1976.

9.2 *American Society for Testing and Materials.* Annual Book of ASTM Standards. Part 31; Water, Atmospheric Analysis. Philadelphia, Pa. 1974. p. 40-42.

9.3 *Klein, R. and C. Hach.* Standard Additions—Uses and Limitations in Spectrophotometric Analysis. *Amer. Lab.* 9:21-27. 1977.

9.4 *Mitchell, W. J. and M. R. Midgett.* Determining Inorganic and Alkyl Lead Emissions from Stationary Sources. U.S. Environmental Protection Agency, Emission Monitoring and Support Laboratory. Research Triangle Park, NC. (Presented at National APCA Meeting. Houston. June 26, 1978.)

9.5 Same as Method 5, Citations 2 to 5 and 7 of Section 7.

* * * * *

(Sections 111, 114, and 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7414, and 7601(a)))

[FR Doc. 80-1078 Filed 1-11-80; 8:45 am]

BILLING CODE 6560-01-M

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

AUTOMOBILE AND LIGHT-DUTY TRUCK SURFACE COATING OPERATIONS

SUBPART MM

40 CFR Part 60

[FRL-1285-4]

Automobile and Light-Duty Truck Surface Coating Operations; Standards of Performance

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: Standards of performance are proposed to limit emissions of volatile organic compounds (VOC) from new, modified, and reconstructed automobile and light-duty truck surface coating operations within assembly plants. Three new test methods are also proposed. Reference Method 24 (Candidate 1 or Candidate 2) would be used to determine the VOC content of coating materials, and Reference Method 25 would be used to determine the percentage reduction of VOC emissions achieved by add-on emission control devices.

The standards implement the Clean Air Act and are based on the Administrator's determination that automobile and light-duty truck surface coating operations within assembly plants contribute significantly to air pollution. The intent is to require new, modified, and reconstructed automobile and light-duty truck surface coating operations to use the best demonstrated system of continuous emission reduction, considering costs, nonair quality health, and environmental and energy impacts.

A public hearing will be held to provide interested persons an opportunity for oral presentation of data, views, or arguments concerning the proposed standards.

DATES: *Comments.* Comments must be received on or before December 14, 1979

Public Hearing. The public hearing will be held on November 9, 1979, at 9 a.m.

Request to Speak at Hearing. Persons wishing to present oral testimony should contact EPA by November 2, 1979

ADDRESSES: *Comments.* Comments should be submitted to: Central Docket Section (A-130), Attention: Docket Number A-79-05, U.S. Environmental Protection Agency, 401 M Street SW., Washington, D.C. 20460.

Public Hearing. The public hearing will be held at National Environmental Resource Center (NERC), Rm. B-102, R.T.P., N.C. Persons wishing to present oral testimony should notify Ms. Shirley Tabler, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5421.

Background Information Document. The Background Information Document (BID) for the proposed standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Automobile and Light-Duty Truck Surface Coating Operations—Background Information for Proposed Standards," EPA-450/3-79-030.

Docket. The Docket, number A-79-05, is available for public inspection and copying at the EPA's Central Docket Section, Room 2903 B, Waterside Mall, Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Proposed Standards

The proposed standards would apply to new automobile and light-duty truck surface coating operations. Existing plants would not be covered unless they undergo modifications resulting in increased emissions or reconstructions. The proposed standards would apply to each prime coat operation, each guide coat operation, and each topcoat operation within an assembly plant. Emissions of VOC from each of these operations would be limited as follows: 0.10 kilogram of VOC (measured as mass of carbon) per liter of applied coating solids from prime coat operations, 0.84 kilogram of VOC (measured as mass of carbon) per liter applied coating solids from guide coat operations, 0.84 kilogram of VOC (measured as mass of carbon) per liter of applied coating solids from topcoat operations.

These proposed emission limits are based on Method 24 (Candidate 1) which determines VOC content of coatings expressed as the mass of carbon. At the time the standards were developed, it was believed that VOC emissions should be determined from carbon measurements. Method 24 (Candidate 1) was developed to measure carbon directly and thus improve the accuracy of the previously used ASTM procedure D 2369-73, which measures the mass of volatile organics indirectly. However, questions have been raised concerning the validity of using the carbon method since the ratio of mass of carbon to mass of VOC in solvents used in automotive coatings varies over a wide range. The effect which this variation might have on the standards is still being investigated. Method 24 (Candidate 2) was developed as a test method for determining VOC emissions from coating materials in terms of mass of volatile organics and is also derived from ASTM procedure D 2369-73. The proposed emission limits, based on Method 24 (Candidate 2) which measures volatile organics, are: 0.16 kilogram of VOC per liter of applied coating solids from prime coat operations, and 1.36 kilogram of VOC per liter of applied coating solids for guide coat operations, and 1.36 kilogram of VOC per liter of applied coating solids from top coat operations. In order to provide an opportunity for public comment on both test methods, both are being proposed, and the final selection of a test method will be made before promulgation, based on the comments received.

Although the emission limits are based on the use of water-based coating materials in each coating operation, they can also be met with solvent-based coating materials through the use of other control techniques, such as incineration. Exemptions are included in the proposed standards which specifically exclude annual model changeovers from consideration as modifications.

Summary of Environmental, Energy, and Economic Impacts

Environmental, energy, and economic impacts of standards of performance are normally expressed as incremental differences between the impacts from a facility complying with the proposed standard and those for one complying with a typical State Implementation Plan (SIP) emission standard. In the case of automobile and light-duty truck surface coating operations, the incremental differences will depend on the control levels that will be required by revised SIP's. Revisions to most SIP's are currently in progress.

Most existing automobile and light-duty truck surface coating operations are located in areas which are considered nonattainment areas for purposes of achieving the National Ambient Air Quality Standard (NAAQS) for ozone. New facilities are expected to locate in similar areas. States are in the process of revising their SIP's for these areas and are expected to include revised emission limitations for automobile and light-duty truck surface coating operations in their new SIP's. In

revising their SIP's the States are relying on the control techniques guideline document, "Control of Volatile Organic Emissions from Existing Stationary Sources—Volume II: Surface Coating of Cans, Coil, Paper, Fabrics, Automobiles and Light-Duty Trucks" (EPA-450/2-77-088 [CTG]).

Since control technique guidelines are not binding, States may establish emission limits which differ from the guidelines. To the extent States adopt the emission limits recommended in the control techniques guideline document as the basis for their revised SIP's, the proposed standards of performance would have little environmental, energy, or economic impacts. The actual incremental impacts of the proposed standards of performance, therefore, will be determined by the final emission limitations adopted by the States in their revised SIP's. For the purpose of this rulemaking, however, the environmental, energy, and economic impacts of the proposed standards have been estimated based on emission limits contained in existing SIP's.

In addition to achieving further reductions in emissions beyond those required by a typical SIP, standards of performance have other benefits. They establish a degree of national uniformity to avoid situations in which some States may attract industries by relaxing air pollution standards relative to other States. Further, standards of performance improve the efficiency of case-by-case determinations of best available control technology (BACT) for facilities located in attainment areas, and lowest achievable emission rates (LAER) for facilities located in nonattainment areas, by providing a starting point for the basis of these determinations. This results from the process for developing a standard of performance, which involves a comprehensive analysis of alternative emission control technologies and an evaluation and verification of emission test methods. Detailed cost and economic analyses of various regulatory alternatives are presented in the supporting documents for standards of performance.

Based on emission control levels contained in existing SIP's, the proposed standards of performance would reduce emissions of VOC from new, modified, or reconstructed automobile and light-duty truck surface coating operations by about 80 percent. National emissions of VOC would be reduced by about 4,800 metric tons per year by 1983.

Water pollution impacts of the proposed standards would be relatively small compared to the volume and quality of the wastewater discharged from plants meeting existing SIP levels. The proposed standards are based on the use of water-based coating materials. These materials would lead to a slight increase in the chemical oxygen demand (COD) of the wastewater discharged from the surface coating operations within assembly plants. This increase in COD, however, is not great enough to require additional wastewater treatment capacity beyond that required in existing assembly plants using solvent-based surface coating materials.

The solid waste impact of the proposed standards would be negligible compared to the amount of solid waste generated by existing assembly plants. The solid waste generated by water-based coatings, however, is very sticky, and equipment cleanup is more time consuming than for solvent-based coatings. Solid wastes from water-based coatings do not present any special disposal problems since they can be disposed of by conventional landfill procedures.

National energy consumption would be increased by the use of water-based coatings to comply with the proposed standards. The equivalent of an additional 18,000 barrels of fuel oil would be consumed per year at a typical assembly plant. This is equivalent to an increase of about 25 percent in the energy consumption of a typical surface coating operation. National energy consumption would be increased by the equivalent of about 72,000 barrels of fuel oil per year in 1983. This increase is based on the projection that four new assembly plants will be built by 1983.

The proposed standards would increase the capital and annualized costs of new automobile and light-duty truck surface coating operations within assembly plants. Capital costs for the four new facilities planned by 1983 would be increased by approximately $19 million as a result of the proposed standards. The incremental capital costs for control represent about 0.2 percent of the $10 billion planned for capital expenditures. The corresponding annualized costs would be increased by approximately $9 million in 1983. The price of an automobile or light-duty truck manufactured at a new plant which complies with the proposed standards of performance would be increased by less than 1 percent. This is considered to be a reasonable control cost.

Modifications and Reconstructions

During the development of the proposed standards, the automobile industry expressed concern that changes to assembly plants made only for the purpose of annual model changeovers would be considered a modification or reconstruction as defined in the Code of Federal Regulations, Title 40, Parts 60.14 and 60.15 (40 CFR 60.14 and 60.15). A modification is any physical or operational change in an existing facility which increases air pollution from that facility. A reconstruction is any replacement of components of an existing facility which is so extensive that the capital cost of the new components exceeds 50 percent of the capital cost of a new facility. In general, modified and reconstructed facilities must comply with standards of performance. According to the available information, changes to coating lines for annual model changeovers do not cause emissions to increase significantly. Further, these changes would normally not require a capital expenditure that exceeds the 50 percent criterion for reconstruction. Hence, it is very unlikely that these annual facility changes would be considered either modifications or reconstructions. Therefore, the proposed standards state that changes to surface coating operations made only to accommodate annual model changeovers are not modifications or reconstructions. In addition, by exempting annual model changeovers, enforcement efforts are greatly reduced with little or no adverse environmental impact.

Selection of Source and Pollutants

VOC are organic compounds which participate in atmospheric photochemical reactions or are measured by Reference Methods 24 (Candidate 1 or Candidate 2) and 25. There has been some confusion in the past with the use of the term "hydrocarbons." In addition to being used in the most literal sense, the term "hydrocarbons" has been used to refer collectively to all organic chemicals. Some organics which are photochemical oxidant precursors are not hydrocarbons (in the strictest definition) and are not always used as solvents. For purposes of this discussion, organic compounds include all compounds of carbon except carbonates, metallic carbides, carbon monoxide, carbon dioxide and carbonic acid.

Ozone and other photochemical oxidants result in a variety of adverse impacts on health and welfare, inducing impaired respiratory function, eye irritation, deterioration of materials such as rubber, and necrosis of plant tissue. Further information on these effects can be found in the April 1978 EPA document "Air Quality Criteria for Ozone and Other Photochemical Oxidants," EPA-600/8-78-004. This

document can be obtained from the EPA library (see Addresses Section).

Industrial coating operations are a major source of air pollution emissions of VOC. Most coatings contain organic solvents which evaporate upon drying of the coating, resulting in the emission of VOC. Among the largest individual operations producing VOC emissions in the industrial coating category are automobile and light-duty truck surface coating operations. Since the surface coating operations for automobiles and light-duty trucks are very similar in nature, with line speed being the primary difference, they are being considered together in this study. Automobile and light-duty truck manufacturers employ a variety of surface coatings, most often enamels and lacquers, to produce the protective and decorative finishes of their product. These coatings normally use an organic solvent base, which is released upon drying.

The "Priority List for New Source Performance Standards under the Clean Air Act Amendments of 1977," which was promulgated in 40 CFR 60.16, 44 FR 49222, dated August 21, 1979, ranked sources according to the impact that standards promulgated in 1980 would have on emissions in 1990. Automobile and light-duty truck surface coating operations rank 27 out of 59 on this list of sources to be controlled.

The surface coating operation is an integral part of an automobile or light-duty truck assembly plant, accounting for about one-quarter to one-third of the total space occupied by a typical assembly plant. Surface coatings are applied in two main steps, prime coat and topcoat. Prime coats may be water-based or organic solvent-based. Water-based coatings use water as the main carrier for the coating solids, although these coatings normally contain a small amount of organic solvent. Solvent-based coatings use organic solvent as the coating solids carrier. Currently about half of the domestic automobile and light-duty truck assembly plants use water-based prime coats.

Where water-based prime coating is used, it is usually applied by EDP. The EDP coat is normally followed by a "guide coat," which provides a suitable surface for application of the topcoat. The guide coat may be water-based or solvent-based.

Automobile and light-duty truck topcoats presently being used are almost entirely solvent-based. One or more applications of topcoats are applied to ensure sufficient coating thinkness. An oven bake may follow each topcoat application, or the coating may be applied wet on wet.

In 1976, nationwide emissions of VOC from automobile and light-duty truck surface coating operations totaled about 135,000 metric tons. Prime and guide coat operations accounted for about 50,000 metric tons with the remaining 85,000 metric tons being emitted from topcoat operations. This represents almost 15 percent of the volative organic emissions from all industrial coating operations.

VOC comprise the major air pollutant emmitted by automobile and light-duty truck assembly plants. Technology is available to reduce VOC emissions and thereby reduce the formation of ozone and other photochemical oxidants. Consequently, automobile and light-duty truck surface coating operations have been selected for the development of standards of performance.

Selection of Affected Facilities

The prime coat, guide coat, and topcoat operations usually account for more than 80 percent of the VOC emissions from autombile and light-duty truck assembly plants. The remaining VOC emissions result from final topcoat repair, cleanup, and coating of various small component parts. These VOC emission sources are much more difficult to control than the main surface coating operations for several reasons. First, water-based coatings cannot be used for final topcoat repair, since the high temperatures required to cure water-based coatings may damage heat sensitive components which have been attached to the vehicle by this stage of production. Second, the use of solvents is required for equipment cleanup procedures. Third, add-on controls, such as incineration, cannot be used effectively on these cleanup operations because they are composed of numerous small operations located throughout the plant. Since prime coat, guide coat, and topcoat operations account for the bulk of VOC emissions from autombile and light-duty truck assembly plants, and control techniques for reducing VOC emissions from these operations are demonstrated, they have been selected for control by standards of performance.

The "affected facility" to which the proposed standards would apply could be designated as the entire surface coating line or each individual surface coating operation. A major consideration in selecting the affected facility was the potential effect that the modification and reconstruction provisions under 40 CFR 60.14 and 60.15, which apply to all standards of performance, could have on existing assembly plants. A modification is any physical or operational change in an existing facility which increases air pollution from that facility. A reconstruction is any replacement of components of an existing facility which is so extensive that the capital cost of the new componensts exceeds 50 percent of the capital cost of a new facility. For standards of performance to apply, EPA must conclude that it is technically and economically feasible for the reconstructed facility to meet the standards.

Many automobile and light-duty truck assembly plafits that have a spray prime coat system will be switching to EDP prime coat systems in the future to reduce VOC emissions to comply with revised SIP's. The capital cost of this change could be greater than 50 percent of the capital cost of a new surface coating line. If the surface coating line were chosen as the affected facility, and if this switch to an EDP prime coat system were considered a reconstruction of the surface coating line, all surface coating operations on the line would be required to comply with the proposed standards. Most plants would be reluctant to install an EDP prime coat system to reduce VOC emissions if, by doing so, the entire surface coating line might then be required to comply with standards of performance. By designating the prime coat, guide coat, and topcoat operations as separate affected facilities, this potential problem is avoided. Thus, each surface coating operation (i.e., prime coat, guide coat, and topcoat) has been selected as an affected facility in the proposed standards.

Selection of Best System of Emission Reduction

VOC emissions from automobile and light-duty truck surface coating operations can be controlled by the use of coatings having a low organic solvent content, add-on emissions control devices, or a combination of the two. Low organic solvent coatings consist of water-based enamels, high solids enamels, and powder coatings. Add-on emission control devices consist of such techniques as incineration and carbon adsorption.

Control Technologies

Water-based coating materials are applied either by conventional spraying or by EDP. Application of coatings by EDP involves dipping the automobile or truck to be coated into a bath containing a dilute water solution of the coating material. When charges of opposite polarity are applied to the dip tank and vehicle, the coating material deposits on the vehicle. Most EDP systems presently in use are anodic systems in which the vehicle is given a positive charge.

Cathodic EDP, in which the vehicle is negatively charged, is a new technology which is expanding rapidly in the automotive industry. Cathodic EDP provides better corrosion resistance and requires lower cure temperatures than anodic systems. Cathodic EDP systems are also capable of applying better coverage on deep recesses of parts.

The prime coat is usually followed by a spray application of an intermediate coat, or guide coat, before topcoat application. The guide coat provides the added film thickness necessary for sanding and a suitable surface for topcoat application. EDP can only be used if the total film thickness on the metal surface does not exceed a limiting value. Since this limiting thickness is about the same as the thickness of the prime coat, spraying has to be used for guide coat and topcoat application of water-based coatings.

Currently, nearly half of domestic automobile and light-duty truck assembly plants use EDP for prime coat application, but only two domestic plants use water-based coating for guide coat and topcoat applications.

Coatings whose solids content is about 45 to 60 percent are being developed by a number of companies. When these coatings are applied at high transfer efficiency rates, VOC emissions are significantly less than emissions from existing solvent-based systems. While these high solids coatings could be used in the automotive industry, certain problems must be overcome. The high working viscosity of these coatings makes them unsuitable for use in many existing application devices. In addition, this high viscosity can produce an "orange peel," or uneven, surface. It also makes these coatings unsuitable for use with metallic finishes. Metallic finishes, which account for about 50 percent of domestic demand, are produced by adding small metal flakes to the paint. As the paint dries, these flakes become oriented parallel to the surface. With high solids coatings, the viscosity of the paint prevents movement of the flakes, and they remain randomly oriented, producing a rough surface. However, techniques such as heated application are being investigated to reduce these problems, and it is expected that by 1982 high solids coatings will be considered technically demonstrated for use in the automotive industry.

Powder coatings are a special class of high solids coatings that consist of solids only. They are applied by electrostatic spray and are being used on a limited basis for topcoating automobiles, both foreign and domestic. The use of powder coatings is severely limited, however, because metallic finishes cannot be applied using powder. As with other high solids coatings, research is continuing in the use of powder coatings for the automotive industry.

Thermal incineration has been used to control VOC emissions from bake ovens in automobile and light-duty truck surface coating operations because of the fairly low volume and high VOC concentration in the exhaust stream. Incineration normally achieves a VOC emission reduction of over 90 percent. Thermal incinerators have not, however, been used for control of spray booth VOC emissions. Typically, the spray booth exhaust stream is a high volume stream (95,000 to 200,000 liters per second) which is very low in concentration of VOC (about 50 ppm). Thermal incineration of this exhaust stream would require a large amount of supplemental fuel, which is its main drawback for control of spray booth VOC emissions. There are no technical problems with the use of thermal incineration.

Catalytic incineration permits lower incinerator operating temperatures and, therefore, requires about 50 percent less energy than thermal incineration. Nevertheless, the energy consumption would still be high if catalytic incineration were used to control VOC emissions from a spray booth. In addition, catalytic incineration allows the owner or operator less choice in selecting a fuel; it requires the use of natural gas to preheat the exhaust gases, since oil firing tends to foul the catalyst. While catalytic incineration is not currently being employed in automobile and light-duty truck surface coating operations for control of VOC emissions, there are no technical problems which would preclude its use on either bake oven or spray booth exhaust gases. The primary limiting factor is the high energy consumption of natural gas, if catalytic incineration is used to control emissions from spray booths.

Carbon adsorption has been used successfully to control VOC emissions in a number of industrial applications. The ability of carbon adsorption to control VOC emissions from spray booths and bake ovens in automobile and light-duty truck surface coating operations, however, is uncertain. The presence of a high volume, low VOC exhaust stream from spray booths would require carbon adsorption units much larger than any that have ever been built. For bake ovens in automobile and light-duty truck surface coating operations, a major impediment to the use of carbon adsorption is heat. The high temperature of the bake oven exhaust stream would require the use of refrigeration to cool the gas stream before it passes through the carbon bed. Carbon adsorption, therefore, is not considered a demonstrated technology at this time for controlling VOC emissions from automobile and light-duty truck surface coating operations. Work is continuing within the automotive industry on efforts to apply carbon adsorption to the control of VOC emissions, however, and it may become a demonstrated technology in the near future.

Regulatory Options

Water-based coatings and incineration are two well-demonstrated and feasible techniques for controlling emissions of VOC from automobile and light-duty truck surface coating operations. Based upon the use of these two VOC emission control techniques, the following two regulatory options were evaluated.

Regulatory Option I includes two alternatives which achieve essentially equivalent control of VOC emissions Alternative A is based on the use of water-based prime coats, guide coats, and topcoats. The prime coat would be applied by EDP. Since the guide coat is essentially a topcoat material, guide coat emission levels as low as those achieved by water-based topcoats should be possible through a transfer of technology from topcoat operations to guide coat operations. Alternative B is based on the use of a water-based prime coat applied by EDP and solvent-based guide coats and topcoats. Incineration of the exhaust gas stream from the topcoat spray booth and bake oven would be used to control VOC emissions under this alternative.

Regulatory Option II is based on the use of a water-based prime coat applied by EDP and solvent-based guide coats and topcoats. In this option, the exhaust gas streams from both the guide coat and topcoat spray booths and bake ovens would be incinerated to control VOC emissions

Environmental, Energy, and Economic Impacts

Standards based on Regulatory Option I would lead to a reduction in VOC emissions of about 80 percent, and standards based on Regulatory Option II would lead to a reduction in emissions of about 90 percent, compared to VOC emissions from automobile and light-duty truck surface coating operations controlled to meet current SIP requirements. Growth projections indicate there will be four new automobile and light-duty truck

assembly lines constructed by 1983. Very few, if any, modifications or reconstructions are expected during this period. Based on these projections, national VOC emissions in 1983 would be reduced by about 4,800 metric tons with standards based on Regulatory Option I and about 5,400 metric tons with standards based on Regulatory Option II. Thus, both regulatory options would result in a significant reduction in VOC emissions from automobile and light-duty truck surface coating operations.

With regard to water pollution, standards based on Regulatory Option II would have essentially no impact. Similarly, standards based on Regulatory Option I(B) would have no water pollution impact. Standards based on Regulatory Option I(A), however, would result in a slight increase in the chemical oxygen demand (COD) of the wastewater discharged from automobile and light-duty truck surface coating operations within assembly plants. This increase is due to water-miscible solvents in the water-based guide coats and topcoats which become dissolved in the wastewater. The increase in COD of the wastewater, however, would be small relative to current COD levels at plants using solvent-based surface coatings and meeting existing SIP's. In addition, this increase would not require the installation of a larger wastewater treatment facility than would be built for an assembly plant which used solvent-based surface coatings.

The solid waste impact of the proposed standards would be negligible. The volume of sludge generated from water-based surface coating operations is approximately the same as that generated from solvent-based surface coating operations. The solid waste generated by water-based coatings, however, is very sticky, and equipment cleanup is more time consuming than for solvent-based coatings. Sludge from either type of system can be disposed of by conventional landfill procedures without leachate problems.

With regard to energy impact, standards based on Regulatory Option I(A) would increase the energy consumption of surface coating operations at a new automobile or light-duty truck assembly plant by about 25 percent. Regulatory Option I(B) would cause an increase of about 150 to 425 percent in energy consumption. Standards based on Regulatory Option II would result in an increase of 300 to 700 percent in the energy consumption of surface coating operations at a new automobile or light-duty truck assembly plant. The range in energy consumption for those options which are based on use of incineration reflects the difference between catalytic and thermal incineration.

The relatively high energy impact of standards based on Regulatory Option I(B) and Regulatory Option II is due to the large amount of incineration fuel needed. Standards based on Regulatory Option II would increase energy consumption at a new automobile and light-duty truck assembly plant by the equivalent of about 200,000 to 500,000 barrels of fuel oil per year, depending upon whether catalytic or thermal incineration was used. Standards based on Regulatory Option I(B) would increase energy consumption by the equivalent of about 100,000 to 300,000 barrels of fuel oil per year.

Standards based on Regulatory Option I(A) would increase the energy consumption of a typical new automobile and light-duty truck assembly plant by the equivalent of about 18,000 barrels of fuel oil per year. Approximately one-third of this increase in energy consumption is due to the use of air conditioning, which is necessary with the use of water-based coatings, and the remaining two-thirds are due to the increased fuel required in the bake ovens for curing water-based coatings.

Growth projections indicate that four new automobile and light-duty truck assembly lines (two automobile and two truck lines) will be built by 1983. Based on these projections, standards based on Regulatory Option I(A) would increase national energy consumption in 1983 by the equivalent of about 72,000 barrels of fuel oil. Standards based on Regulatory Option I(B) would increase national energy consumption in 1983 by the equivalent of 400,000 to 1,200,000 barrels of fuel oil, depending on whether catalytic or thermal incineration were used. Standards based on Regulatory Option II would increase national energy consumption in 1983 by the equivalent of 800,000 to 2,000,000 barrels of fuel oil, again depending on whether catalytic or thermal incineration were used.

The economic impacts of standards based on each regulatory option were estimated using the growth projection of four new assembly lines by 1983. Incremental control costs were determined by calculating the difference between the capital and annualized costs of new assembly plants controlled to meet Regulatory Options I(A), I(B), and II, respectively, with the corresponding costs for new plants designed to comply with existing SIP's. Of the four assembly plants projected by 1983, two were assumed to be lacquer lines and the other two enamel lines. There are basic design differences between these two types of surface coatings which have a substantial impact on the magnitude of the costs estimated to comply with standards of performance. Lacquer surface coating operations, for example, require much larger spray booths and bake ovens than enamel surface coating operations. Water-based systems also require large spray booths and bake ovens; thus, the incremental capital cost of installing a water-based system in a plant which would otherwise have used a lacquer system is relatively low. The incremental capital costs differential, however, would be much larger if the plant would have been designed for an enamel system.

Tables 1 and 2 summarize the economic impacts of the proposed standards on plants of typical sizes. Table 1 presents the incremental costs of the various control options for a plant which would have used solvent-based lacquers. Table 2 presents similar costs for plants which would have been designed to use solvent-based enamels. Though these tables present incremental costs for passenger car plants, light-duty truck plants would have similar cost differentials. In all cases, it is assumed the plants would install a water-based EDP prime system in the absence of standards of performance. Therefore, no incremental costs associated with EDP prime coat operations are included in the costs presented in Tables 1 and 2. A nominal production rate of 55 passenger cars per hour was assumed for both plants. Tables 1 and 2 show incremental capitalized and annualized costs per vehicle produced at each new facility. The manufacturers would probably distribute these incremental costs over their entire annual production to arrive at purchase prices for the automobiles and light-duty trucks.

Table 1 INCREMENTAL CONTROL COSTS[a]

(Compared to the Costs of a Lacquer Plant)

	Regulatory Options				
	I(A)	I(B)		II	
	Water-Based Coatings	Thermal	Catalytic	Thermal	Catalytic
Capital Cost of Control Alternative	$ 720,000	$11,800,000	$15,000,000	$12,800,000	$16,200,000
Annualized Cost of Control Alternative	$1,550,000	$14,500,000	$10,700,000	$15,500,000	$11,500,000
Incremental Cost/Vehicle Produced at this Facility	$7 34	$68 66	$50 66	$73.39	$54 45

[a]Assumes a line speed of 55 vehicles per hour and an annual production of 211,200 vehicles

Table 2 INCREMENTAL CONTROL COSTS[a]

(Compared to the Costs of an Enamel Plant)

	Regulatory Options				
	I(A)	I(B)		II	
	Water-Based Coatings	Thermal	Catalytic	Thermal	Catalytic
Capital Cost of Control Alternative	$10,300,000	$ 4,630,000	$ 5,850,000	$ 5,640,000	$ 7,000,000
Annualized Cost of Control Alternative	$ 3,640,000	$ 5,620,000	$ 4,150,000	$ 6,610,000	$ 4,890,000
Incremental Cost/Vehicle Produced at this Facility	$17 23	$26.61	$19 65	$31.30	$23 15

[a]Assumes a line speed of 55 vehicles per hour and an annual production of 211,200 vehicles.

Incremental capital costs for suing incineration to reduce VOC emissions from solvent-based lacquer plants to levels comparable to water-based plants are much larger than they are for using incineration on a solvent-based enamel plant. This large difference in costs occurs because lacquer plants have larger spray booth and bake oven areas than enamel plants and, therefore, a larger volume of exhaust gases. Since larger incineration units are required, the incremental capital costs of using incineration to control VOC emissions from a solvent-based lacquer plant are about 15 to 25 times greater than they are for using water-based coatings. Similarly, energy consumption is much greater; hence, the annualized costs of using incineration are about 10 times greater than they are for using water-based coatings.

On the other hand, the incremental capital costs of controlling VOC emissions from new solvent-based enamel plants by the use of incineration are only about one-half the incremental capital costs between a new solvent-based enamel plant and a new water-based plant. Due to the energy consumption associated with incinerators, however, the incremental annualized costs of using incineration with solvent-based enamel coatings could vary from as little as 15 percent more to as much as 90 percent more than the annualized costs of using water-based coatings.

While the incremental capital costs of building a plant to use water-based coatings can be larger or smaller than the costs of using incineration, depending upon whether a solvent-based lacquer plant or a solvent-based enamel plant is used as the starting point, the annualized costs of using water-based coatings are always less than they are for using incineration. This is due to the large energy consumption of incineration units compared to the energy consumption of water-based coatings.

Since the incremental annualized costs are less with Regulatory Option I(A) than with Regulatory Option I(B), it is assumed in this analysis that Regulatory Option I(A) would be incorporated at any new, modified, or reconstructed facility to comply with standards based on Regulatory Option I. As noted, four new assembly plants are expected to be built by 1983. The incremental capital cost to the industry for these plants to comply with standards based on Regulatory Option I would be approximately $19 million. The corresponding incremental annualized costs would be about $9 million in 1983. If standards are based on Regulatory Option II, it is expected that the industry would choose catalytic incineration because its annualized costs are lower than those for thermal incineration. Based this assumption, the incremental capital costs for the industry under Regulatory Option II would be approximately $42 million, and the incremental annualized costs by 1983 would be about $30 million. For standards based on either Regulatory Option I or Regulatory Option II, the increase in the price of an automobile or light-duty truck that is manufactured at one of the new plants would be less than 1 percent of the base price of the vehicle.

Best System of Emission Reduction

Both Regulatory Options I and II achieve a significant reduction in VOC emissions compared to automobile and light-duty truck assembly plants controlled to comply with existing SIP's, and neither option creates a significant adverse impact on other environmental media. In terms of energy consumption, standards based on Regulatory Option II would have as much as 10 to 25 times the adverse impact on energy consumption as standards based on Regulatory Option I, while only achieving 10 to 15 percent more reductions in VOC emissions. The costs of standards based on Regulatory Option II range from two to three times the costs of standards based on Regulatory Option I. Thus, Regulatory Option I(A), water-based coatings, was selected as the best system of continuous emission reduction, considering costs and nonair quality health, and environmental and energy impacts.

Although water-based coatings are considered to be the best system of emission reduction at the present time, it is very likely that plants built in the future will use other systems to control VOC emissions, such as high solids coatings and powder coatings. High solids coatings applied at high transfer efficiencies are capable of achieving equivalent emission reductions and are expected to be less costly and require less total energy than water-based systems. These high solids coatings are expected to be available by 1982 and will probably be used by most new sources to comply with the VOC emission limitations. Powder coatings are also expected to be available in the future but are not demonstrated at this time.

Selection of Format for the Proposed Standards

A number of different formats could be selected to limit VOC emissions from automobile and light-duty truck surface coating operations. The format ultimately selected must be compatible with any of the three different control systems that could be used to comply with the proposed standards. One control system is the use of water-based coating materials in the prime coat, guide coat, and topcoat operations. Another control system is the use of solvent-based coating materials and add-on VOC emission control devices such as incineration. The third control system consists of the use of high solids coatings. Although the coatings to be used in this system are not demonstrated at this time, research is continuing toward their development; hence, they may be used in the future.

The formats considered were emission limits expressed in terms of (1) concentration of emissions in the exhaust gases discharged to the atmosphere; (2) mass emissions per unit of production; or (3) mass emissions per volume of coating solids applied.

The major advantage of the concentration format is its simplicity of enforcement. Direct emission measurements could be made using Reference Method 25. There are, however, two significant drawbacks to the use of this format. Regardless of the control approach chosen, emission testing would be required for each stack exhausting gases from the surface coating operations (unless the owner or operator could demonstrate to the Administrator's satisfaction that testing of representative stacks would give the same results as testing all the stacks). This testing would be time consuming and costly because of the large number of stacks associated with automobile and light-duty truck surface coating operations. Another potential problem with this format is the ease of circumventing the standards by the addition of dilution air. It would be extremely difficult to determine whether diluted air was being added intentionally to reduce the concentration of VOC emissions in the gases discharged to the atmosphere, or whether the air was being added to the application or drying operation to optimize performance and maintain a safe working space.

A format of mass VOC emissions per unit of production relates emissions to individual plant production on a direct basis. Where water-based coatings are used, the average VOC content of the coating materials could be determined

by using Reference Method 24 (Candidate 1 or Candidate 2). The volume of coating materials used and the percent solids could be determined from purchase records. VOC emissions could then be calculated by multiplying the VOC content of the coating materials by the volume of coating materials used in a given time period and by the percentage of solids, and dividing the result by the number of vehicles produced in that time period. This would provide a VOC emission rate per unit of production. Consequently, procedures to determine compliance would be direct and straightforward, although very time consuming. This procedure would also require data collection over an excessively long period of time.

Where solvent-based coatings were used with add-on emission control devices, stack emission tests could be performed to determine VOC emissions. Dividing VOC emissions by the number of vehicles produced would again yield VOC emissions per unit of production. This format, however, would not account for differences in surface coating requirements for different vehicles caused by size and configuration. In addition, manufactureres of larger vehicles would be required to reduce VOC emissions more than manufacturers of smaller vehicles.

A format of mass of VOC emissions per volume of coating solids applied also has the advantage of not requiring stack emission testing unless add-on emission control devices rather than water-based coatings are used to comply with the standards. The introduction of dilution air into the exhaust stream would not present a problem with this format. The problem of varying vehicle sizes and configurations would be eliminate since the format is in terms of volume of applied solids regardless of the surface area or number of vehicles coated. This format would also allow flexibility in selection of control systems, for it is usable with any of the control methods. Since this format overcomes the varying dilution air and vehicle size problems inherent with the other formats, it has been selected as the format for the proposed standards. In order to use a format which is in terms of applied solids, the transfer efficiency of the application devices must be considered. Transfer efficiency is defined as the fraction of the total sprayed solids which remain on the vehicle. Transfer efficiency is an important factor because as efficiency decreases, more coating material is used and VOC emissions increase. Equations have been developed to use this format with water-based coating materials as well as with solvent-based coating materials in combination with high transfer efficiences and/or add-on emission controls devices. These equations are included in the proposed standards.

Selection of Numerical Emission Limits

Numerical Emission Limits

The numerical emission limits selected for the proposed standard are:

- 0.10 kilogram of VOC per liter of applied coating solids from prime coat operations
- 0.84 kilogram of VOC per liter of applied coating solids from guide coat operations
- 0.84 kilogram of VOC per liter of applied coating solids from topcoat operations .

In all three limits, the mass of VOC is measured as carbon in accordance with Reference Methods 24 (Candidate 1) and 25. These emission limits are based on the use of water-based coating materials in the prime coat, guide coat, and topcoat operations. Water-based coating data were obtained from plants which were using these materials as well as from the vendors who supply them. These data were used to calculate VOC emission limits using a procedure similar to proposed Method 24 (Candidate 1). A transfer efficiency of 40 percent was then applied to the values obtained for guide coat and top-coat emissions. This efficiency was determined to be representative of a well-operated air-atomized spray system. The CTG-recommended limits are based on the use of the same coating materials as the proposed standards. The limits in the CTG are expressed in pounds of VOC per gallon of coating (minus water) used in the EDP system or the spray device. The limits in these proposed standards, however, are referenced to the amount of coating solids which adhere to the vehicle body. Therefore, to compare the limits in the CTG to those proposed here, it is necessary to account for the solids content of the coating and the efficiency of applying the guide coat and topcoat to the vehicle body. Consideration of transfer efficiency is significant because the proposed standards can be met by using high solids content coating materials if the amount of overspray is kept to a minimum. Since this format provides equivalency determinations for systems using solvent-based coating materials in combination with high transfer efficiencies and/or add-on control devices, it allows flexibility in selection of control systems.

As discussed in previous sections, there are two types of EDP systems. Anodic EDP was the first type developed for use in automobile surface coating operations. Cathodic EDP is the second type and is a recent technology improvement which results in greater corrosion resistance. Consequently, nearly 50 percent of the existing EDP operations use cathodic systems, and continued changeovers from anodic to cathodic EDP are expected. Since cathodic EDP produces a coating with better corrosion resistance, the proposed standards are based on the best available cathodic EDP systems.

The coating material on which the EDP emission limit is based is presently in production use. Although this low solvent content material is currently available only in limited quantities, it is expected to be available in sufficient quantities for use in all new or modified sources before promulgation of the standard. The final promulgated standards will be based on this low solvent content material, rather than the EDP material commonly used now, if it is determined to be widely available at that time.

The emission limit for guide coat operations is based on a transfer of technology from topcoat operations. The guide coat is essentially a topcoat material, without pigmentation, and water-based topcoats are available which can comply with the proposed limits. Hence, the same emission limit is proposed for the guide coat operation as for the topcoat operation.

Because of the elevated temperatures present in the prime coat, guide coat, and topcoat bake ovens, additional amounts of "cure volatile" VOC may be emitted. These "cure volatile" emissions are present only at high temperatures and are not measured in the analysis which is used to determine the VOC content of coating materials. Cure volatile emissions, however, are believed to constitute only a small percentage of total VOC emissions Consequently, because of the complexity of measuring and controlling cure volatile emissions, they will not be considered in determining compliance with the proposed standards.

A large number of coating materials are used in topcoat operations, and each may have a different VOC content. Hence, an average VOC content of all the coatings used in this operation would be computed to determine compliance with the proposed standards. Either of two averaging techniques could be used for computing this average. Weighted averages provide very accurate results but would require keeping records of the total volume and

percent solids of each different coating used. Arithmetic averages are not always as accurate; however, they are much simpler to calculate. In the case of topcoat operations, normally 15 to 20 different coatings are used, and the VOC content for most of these coatings is in the same general range. Therefore, an arithmetic average would closely approximate the values obtained from a weighted average. An arithmetic average would be calculated by summing the VOC content of each surface coating material used in a surface coating operation (i.e., guide coat or topcoat), and dividing the sum by the number of different coating materials used. Arithmetic averages are also consistent with the approach being incorporated into some revised SIP's.

For the EDP process, however, an arithmetic average VOC content is not appropriate to determine compliance with the proposed standards. In an EDP system, the coating material applied to an automobile or light-duty truck body is replaced by adding fresh coating materials to maintain a relatively constant concentration of solids, solvent, and fluid level in the EDP coating tank. Three different types of materials are usually added in separate streams—clear resin, pigment paste, and solvent.

The clear resin and pigment paste are very low in VOC content (i.e., 10 percent or less), while the solvent is very high in VOC content (i.e., 90 percent or more). The solvent additive stream is only about 2 percent of the total volume added. Consequently, an arithmetic average of the three streams seriously misrepresents the actual amount of VOC added to the EDP coating tank. Weighted averages, therefore, were selected for determining the average VOC content of coating materials applied by EDP.

If an automobile or light-duty truck manufacturer chooses to use a control technique other than water-based coatings, the transfer efficiency of the application devices used becomes very important. As transfer efficiency decreases, more coating material is used and VOC emissions increase. Therefore transfer efficiency must be taken into account to determine equivalency to water-based coatings.

Electrostatic spraying, which applies surface coatings at high transfer efficiences, can in many industries be used with water-based coatings if the entire paint handling system feeding the atomizers is insulated electically from ground. Otherwise, the high conductivity of the water involved would ground out and make ineffective the electrostatic effect. In the case of the coating of automobiles, however, because of the larger number of colors involved, the high frequency and speed of color changes required, the large volume of coatings consumed per shift, and the large number of both automatic and manual atomizers involved, it is not technically feasible to combine water-based coatings and electrostatic methods for reasons of complexity, cost, and personnel comfort. Consequently, water-based surface coatings are applied by air-atomized spray systems at a transfer efficiency of about 40 percent. The numerical emission limits included in the proposed standards were developed based on the use of water-based surface coatings applied at a 40 percent transfer efficiency. Therefore, if surface coatings are applied to a greater than 40 percent transfer efficiency, surface coatings with higher VOC contents may be used with no increase in VOC emissions to the atmosphere. Transfer efficiencies for various means of applying surface coatings have been estimated, based on information obtained from industries and vendors, as follows:

Application method	*Transfer efficiency* (percent)
Air Atomized Spray	40
Manual Electrostatic Spray	75
Automatic Electrostatic Spray	95
Electrodeposition (EDP)	100

These values are estimates which reflect the high side of expected transfer efficiency ranges, and therefore, are intended to be used only for the purpose of determining compliance with the proposed standards.

Frequently, more than one application method is used within a single surface coating operation. In these cases, a weighted average transfer efficiency, based on the relative volume of coating sprayed by each method, will be estimated. These situations are likely to vary among the different manufacturers and the estimates, therefore, will be subject to approval by the Administrator on a case-by-case basis.

Method of Determining Compliance

The procedure for determining compliance with the proposed standards is complicated due to the number of different control systems which may be used. The following multistep procedure would be used.

1. Determine the average VOC content per liter of coating solids of the prime coat, guide coat, and topcoat materials being used. This would require analyzing all coating materials used in each coating operation using the proposed Reference Method 24 (Candidate 1 or Candidate 2) and calculating an average VOC content for each coating operation.

2. Select the appropriate transfer efficiency for each surface coating operation from the table included in the proposed standards.

3. Calculate the mass of VOC emissions per volume of applied solids for each surface coating operation by dividing the appropriate average VOC content of the coatings (Step 1) by the transfer efficiency of the surface coating operation (Step 2). If the value obtained is lower than the emission limit included in the proposed standards, the surface coating operation would be in compliance. If the value obtained is higher than the emission limit, add-on VOC emission control would be required to comply with the proposed standards.

4. If add-on emission control is required, calculate the emission reduction efficiency in VOC emissions which is required using the equations included in the proposed standards.

5. In cases where all exhaust gases are not vented to an emission control device, determine the percentage of total VOC emissions which enter the add-on emission control device by sampling all the stacks and using the equations included in the proposed standards. Representative sampling, however, could be approved by the Administrator, on a case-by-case basis, rather than requiring sampling of all stacks for this determination.

6. Calculate the actual efficiency of the control device by determining VOC emissions before and after the device using the proposed Reference Method 25.

7. Calculate the VOC emission reduction efficiency achieved by multiplying the percentage of VOC emissions which enter the add-on VOC emission control device (Step 5) by the add-on control device efficiency (Step 6). If the resulting value of the emission reduction efficiency achieved were greater than that required (Step 4), then the surface coating operation would be in compliance.

Detailed instructions, as well as the equations to be used for these calculations, are contained in the proposed standards.

Selection of Monitoring Requirements

Monitoring requirements are generally included in standards of performance to provide a means for enforcement personnel to ensure that emission control measures adopted by a facility to comply with standards of performance are properly operated and maintained. Surface coating operations which have achieved compliance with

the proposed standards without the use of add-on VOC emission control devices would be required to monitor the average VOC content (weighted averages for EDP and arithmetic averages for guide coat and topcoat) of the coating materials used in each surface coating operation. Generally, increases in the VOC content of the coating materials would cause VOC emissions to increase. These increases could be caused by the use of new coatings or by changes in the composition of existing coatings. Therefore, following the initial performance test, increases in the average VOC content of the coating materials used in each surface coating operation would have to be reported on a quarterly basis.

Where add-on control devices, such as incinerators, were used to comply with the proposed standards, combustion temperatures would be monitored. Following the initial performance test, decreases in the incinerator combustion temperature would be reported on a quarterly basis.

Performance Test Methods

Reference Method 24, "Determination of Volatile Organic Compound Content of Paint, Varnish, Lacquer, or Related Products," is proposed in two forms—Candidate 1 and Candidate 2. Candidate 1 leads to a determination of VOC content expressed as the mass of carbon. Candidate 2 yields a determination of VOC content measured as mass of volatile organics. The decision as to which Candidate will be used depends on the final format selected for the proposed standards. Reference Method 25, "Determination of Total Gaseous Nonmethane Volatile Organic Compound Emissions," is proposed as the test method to determine the percentage reduction of VOC emissions achieved by add-on emission control devices.

Public Hearing

A public hearing will be held to discuss the proposed standards in accordance with Section 307(d)(5) of the Clean Air Act. Persons wishing to make oral presentations should contact EPA at the address given above (see Addresses Section). Oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement before, during, or within 30 days after the hearing. Written statements should be addressed to "Docket" (see Addresses Section).

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460.

Docket

The docket, containing all supporting information used by EPA to date, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460.

The docket is an organized and complete file of all the information submitted to or otherwise considered by EPA in the development of the rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process. Along with the statement of basis and purpose of the promulgated rule and EPA responses to significant comments, the contents of the Docket will serve as the record in case of judicial review [Section 307(d)(a)].

Miscellaneous

As prescribed by Section 111, establishment of standards of performance for automobile and light-duty truck surface coating operations was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that these sources contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In accordance with Section 117 of the Act, publication of these standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies. The Administrator welcomes comments on all aspects of the proposed regulations, including the technological issues, monitoring requirements, and the proposed test methods. Comments are requested specifically on Method 24 (Candidate 1 and Candidate 2) and the coating material used as the basis for the prime coat emission limit.

It should be noted that standards of performance for new sources established under Section 111 of the Clean Air Act reflect:

> . . . application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [Section 111(a)(1)]

Although emission control technology may be available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance because of costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act may require the imposition of a more stringent emission standard in several situations.

For example, applicable costs do not necessarily play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources locating in nonattainment areas (i.e., those areas where statutorily mandated health and welfare standards are being violated). In this respect, section 173 of the Act requires that new or modified sources constructed in an area which exceeds the NAAQS must reduce emissions to the level which reflects the LAER, as defined in section 171(3). The statute defines LAER as the rate of emissions based on the following, whichever is more stringent:

> (A) the most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or
>
> (B) the most stringent emission limitation which is achieved in practice by such class or category of source.

In no event can the emission rate exceed any applicable new source performance standard.

A similar situation may arise under the prevention-of-significant-deterioration-of-air-quality provisions of the Act. These provisions require that certain sources employ BACT as defined in section 169(3) for all pollutants regulated under the Act. BACT must be determined on a case-by-case basis, taking energy, environmental and economic impacts, and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the Act.

In all cases, SIP's approved or promulgated under section 110 of the Act must provide for the attainment and maintenance of NAAQS designed to protect public health and welfare. For this purpose, SIP's must, in some cases, require greater emission reduction than those required by standards of performance for new sources.

Finally, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

Under EPA's sunset policy for reporting requirements in regulations, the reporting requirements in this regulation will automatically expire 5 years from the date of promulgation unless EPA takes affirmative action to extend them.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance under section 111(b) of the Act. An economic impact assessment was prepared for the proposed regulations and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the proposed standards to ensure that the proposed standards would represent the best system of emission reduction considering costs. The economic impact assessment is included in the Background Information Document.

Dated: September 27, 1979.

Douglas M. Costle,

Administrator.

This proposed amendment to Part 60 of Chapter I, Title 40 of the Code of Federal Regulations would—

1. Add a definition of the term "volatile organic compound" to § 60.2 of Subpart A—General Provisions as follows:

§ 60.2 Definitions.

* * * * *

(dd) "Volatile Organic Compound" means any organic compound which participates in atmospheric photochemical reaction or is measured by the applicable reference methods specified under any subpart.

2. Add Subpart MM as follows:

Subpart MM—Standards of Performance for Automobile and Light-Duty Truck Surface Coating Operations

Sec

60.390 Applicability and designation of affected facility.
60.391 Definitions.
60.392 Standards for volatile organic compounds.
60.393 Monitoring of operations.
60.394 Test methods and procedures.
60.395 Modifications.

Authority: Secs. 111 and 301(a) of the Clean Air Act, as amended, [42 U.S.C. 7411, 7601(a)], and additional authority as noted below.

Subpart MM—Standards of Performance for Automobile and Light-Duty Truck Surface Coating Operations

§ 60.390 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to the following affected facilities in an automobile or light-duty truck surface coating line: each prime coat operation, each guide coat operation, and each topcoat operation.

(b) The provisions of this subpart apply to any affected facility identified in paragraph (a) of this section that begins construction or modification after ———— (date of publication in the Federal Register).

§ 60.391 Definitions.

All terms used in this subpart that are not defined below have the meaning given to them in the Act and in Subpart A of this part.

(a) "Automobile" means a motor vehicle capable of carrying no more than 12 passengers.

(b) "Automobile and light-duty truck body" means the body section rearward of the windshield and the front-end sheet metal or plastic exterior panel material forward of the windshield of an automobile or light-duty truck.

(c) "Bake oven" means a device which uses heat to dry or cure coatings.

(d) "Electrodeposition (EDP)" means a method of applying prime coat. The automobile or light-duty truck body is submerged in a tank filled with coating material, and an electrical field is used to deposit the material on the body.

(e) "Electrostatic spray application" means a spray application method that uses an electrical potential to increase the transfer efficiency of the coating solids. Electrostatic spray application can be used for prime coat, guide coat, or topcoat operations.

(f) "Flash-off area" means the structure on automobile and light-duty truck assembly lines between the coating application system (EDP tank or spray booth) and the bake oven.

(g) "Guide coat operation" means the guide coat spray booth, flash-off area and bake oven(s) which are used to apply and dry or cure a surface coating on automobile and light-duty truck bodies between the prime coat and topcoat operation.

(h) "Light-duty truck" means any motor vehicle rated at 3,850 kilograms (ca. 8,500 pounds) gross vehicle weight or less designed mainly to transport property.

(i) "Prime coat operation" means the prime coat application system (spray booth or dip tank), flash-off area, and bake oven(s) which are used to apply and dry or cure the initial coat on the surface of automobile or light-duty truck bodies.

(j) "Spray application" means a method of applying coatings by atomizing the coating material and directing this atomized spray toward the part to be coated. Spray applications can be used for prime coat, guide coat, and topcoat operations.

(k) "Spray booth" means a structure housing or manual spray application equipment where prime coat, guide coat, or topcoat is applied to automobile or light-duty truck bodies.

(l) "Surface coating operation" means any prime coat, guide coat, or topcoat operation on an automobile or light-duty truck surface coating line.

(m) "Topcoat operation" means the topcoat spray booth(s), flash-off area(s), and bake oven(s) which are used to apply and dry or cure the final coating(s) on automobile and light-duty truck bodies (i.e., those which give an automobile or light-duty truck body its color and surface appearance).

(n) "Transfer efficiency" means the fraction of the total applied coating solids which remains on the part.

(o) "Volatile organic compound" (VOC) means any organic compound which is measured by Method 24 (Candidate 1 or Candidate 2) and Method 25.

(p) "VOC emissions" means the mass of volatile organic compounds, expressed as kilograms of carbon per liter of applied coating solids, emitted from a surface coating operation.

(q) "VOC content" means the volatile organic compound content, in kilograms of carbon per liter of coating solids, of a coating material used in spray applications or coating make-up stream to an EDP tank.

§ 60.392 Standards for volatile organic compounds.

After the performance test required by § 60.8 has been completed, no owner or operator subject to the provisions of this subpart shall discharge or cause of the discharge into the atmosphere of VOC emissions which exceed the following limits:

(a) 0.10 kilogram of VOC (measured as mass of carbon) per liter of applied coating solids from each prime coat operation.

(b) 0.84 kilogram of VOC (measured as mass of carbon) per liter of applied coating solids from each guide coat operation.

(c) 0.84 kilogram of VOC (measured as mass of carbon) per liter of applied coating solids from each topcoat operation.

§ 60.393 Monitoring of operations.

(a) Any owner or operator subject to the provisions of this subpart shall—(1) Install, calibrate, operate, and maintain a monitoring device which records the combustion temperature of any effluent gases which are emitted from any surface coating operation and which are incinerated to comply with § 60.392. The manufacturer must certify that the monitoring device is accurate to within ±2°C (±3.6°F).

(2) Determine the weighted average VOC content of the coating materials used in any EDP prime coat operation whenever a change occurs in the composition of any of these coating materials. The owner or operator shall compute the weighted average by the following equation:

$$C = \frac{\sum_{i=1}^{n} CS_i \times VOLS_i \times SC_i}{\sum_{i=1}^{n} VOLS_i \times SC_i}$$

where:

C = the weighted averaged VOC content of all the coating materials used in an EDP system.

CS_i = the VOC content of the material in each coating makeup stream.

$VOLS_i$ = the volume (cubic meters) of each makeup stream added to the EDP tank during the previous month.

SC_i = the solid content of the material in each coating makeup stream expressed as a volume fraction.

n = the number of makeup streams.

(3) Determine the average VOC content of the coating materials in any surface coating operation which uses spray application whenever a change occurs in the composition of any of these coating materials. The owner or operator shall determine and record the arithmetic average of the VOC content of all coating materials in a coating operation which uses more than one coating material.

(b) Any owner or operator subject to the provisions of this subpart shall report for each calendar quarter all measurement results as follows:

(1) Where compliance with § 60.392 is achieved without the use of add-on control devices, any month during which—

(i) The weighted average VOC content of the makeup materials used in any prime coat operation employing EDP exceeds the most recent value which demonstrated compliance with § 60.392(a) by the performance test required in § 60.8.

(ii) The arithmetic average VOC content of the coating materials used in any surface coating operation employing spray application exceeds the most recent value which demonstrated compliance with § 60.392 by the performance test required in § 60.8.

(2) Where compliance with § 60.392 is achieved by the use of incineration, all periods in excess of 5 minutes during which the temperature in any incinerator used to control the emission from a surface coating operation remains below the most recent level which demonstrated compliance with § 60.392 by the performance tests required in § 60.8. The report required under § 60.7(c) shall identify each such occurrence and its duration.

(3) The reporting requirements in this regulation will automatically expire five years from the date of promulgation unless EPA takes affirmative action to extend them.

§ 60.394 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with § 60.392 as follows:

(1) The owner or operator shall use Reference Method 24 (Candidate 1 or Candidate 2) to measure the VOC content of every coating or makeup material used in each surface coating operation of an automobile or light-duty truck surface coating line. The coating sample shall be a 1 liter sample taken at a point where the sample will be representative of the coating material as applied to the vehicle surface. The 1 liter sample shall be divided into three aliquots for triplicate determinations by Method 24 (Candidate 1 or Candidate 2).

(2) The owner or operator shall compute the arithmetic average VOC content of all coating materials used in each surface coating operation that uses spray application.

(3) The owner or operator shall use the calculation procedures given in § 60.393(a)(2) to compute the weighted average VOC content of all makeup materials added to an EDP tank during a selected one month period for each prime coat operation that uses EDP.

(4) The owner or operator shall determine the VOC emissions by the equation:

$$E = \frac{C}{TE}$$

where

E = the VOC emissions.

C = the average VOC content of all the coating or makeup materials used in that operation. The owner or operator shall use an arithmetic average for systems using spray application and a weighted average for systems using EDP.

TE = the appropriate transfer efficiency as determined in paragraph (a)(5) of this section.

(5) The owner or operator shall select the appropriate transfer efficiency from the following table for each surface coating operation.

Application method	Transfer efficiency (TE)
Air Atomized Spray	0.40
Manual Electrostatic Spray	0.75
Automatic Electrostatic Spray	0.95
Electrodeposition	1.00

If the owner or operator can justify to the Administrator's satisfaction that other values for transfer efficiencies are appropriate, the Administrator will approve their use on a case-by-case basis. Where more than one application method is used on an individual surface coating operation, the owner or operator shall perform an analysis to determine the relative volume of solids coating materials applied by each method. The owner or operator shall use these relative volumes of solids to compute a weighted average transfer efficiency for the operation. The Administrator will review and approve this analysis on a case-by-case basis.

(b) For each surface coating operation which cannot achieve compliance with § 60.392 without the use of add-on control devices, the owner or operator shall use the following procedures to determine that the emission reduction efficiency of the control device(s) is sufficient to achieve compliance with § 60.392:

(1) The owner or operator shall compute the emission reduction efficiency required for each surface coating operation by the following equation:

$$ER = \frac{E - EL}{E} \times 100$$

where:

ER = the required emission reduction efficiency (in percent) for the applicable surface coating operation to achieve compliance with § 60.392.

E = the VOC emissions from the applicable surface coating operation.

EL = the numerical VOC emission limit in § 60.392 for the applicable surface coating operation.

(2) The owner or operator shall determine the emission reduction efficiency achieved by the control device(s) on each applicable surface coating operation as follows:

(i) The owner or operator shall use Reference Method 25 to determine the

VOC concentration in the effluent gas before and after the emission control device for each stack that is equipped with an emission control device. The owner or operator shall use Reference Method 2 to determine the volumetric flowrate of the effluent gas before and after the emission control device on each stack. The Administrator will approve testing of representative stacks, on a case-by-case basis, if the owner or operator can show to the Administrator's satisfaction that testing of representative stacks yields results comparable to those that would be obtained by testing all stacks.

(ii) For Method 25, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be at least 0.003 dscm (0.106 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(iii) The owner or operator shall determine the efficiency of each emission control device by the following equation:

$$EFF = \frac{(CB \times VOLB) - (CA \times VOLA)}{(CB \times VOLB)} \times 100$$

where:

EFF = the emission control device efficiency, in percent.

CB = the concentration of VOC in the effluent gas before the emission control device, in parts per million by volume.

CA = the concentration of VOC in the effluent gas after the emission control device, in parts per million by volume.

VOLA = the volumetric flow rate of the effluent gas after the emission control device, in dry standard cubic meters per second.

VOLB = the volumetric flow rate of the effluent gas before the emission control device, in dry standard cubic meters per second.

If an emission control device controls the emissions from more than one stack, the owner or operator shall measure CB and VOLB at a location between the manifold that receives all the exhausts from the applicable surface coating operation and the control device. If a manifold is not used, the product CB × VOLB shall be replaced by the sum of the individual products for each stack on the applicable surface coating operation controlled by this device.

(iv) The owner or operator shall determine the fraction of the total VOC discharged from an applicable surface coating operation which enters each emission control device on that operation by the following equation:

$$F_i = \frac{CB_i \times VOLB_i}{\sum_{k=1}^{n} (CB_k \times VOLB_k)}$$

where:

F_i = the fraction of the total VOC discharged from the applicable surface coating operation which enters the emission control device.

CB_i = the value of CB for stack (k) on the applicable surface coating operation.

CB_k = the value of CB for each stack (k) on the applicable surface coating operation.

$VOLB_i$ = the value of VOLB for each emission control device (i).

$VOLB_k$ = the value of VOLB for each stack (k) on the applicable surface coating operation.

n = the number of stacks on the applicable surface coating operation.

The owner or operator shall use the procedures contained in clause (ii) of this subparagraph for any emission control device (i) that controls the emissions from more than one stack.

(v) The owner or operator shall determine the emission reduction efficiency achieved by the control device(s) on the applicable surface coating operation using the equation:

$$EA = \sum_{i=1}^{m} (F_i \times EFF_i)$$

where:

EA = the emission reduction efficiency achieved, in percent.

EFF_i = the emission reduction efficiency (in percent) of each control device on the applicable surface coating operation.

m = the number of control devices on the applicable surface coating operation.

(3) If EA is greater than or equal to ER, the applicable surface coating operation will be in compliance with § 60.392.

§ 60.395 Modifications.

(a) The following physical or operational changes are not, by themselves, considered modifications of existing facilities:

(1) Changes as a result of model year changeovers or switches to larger cars.

(2) Changes in the application of the coatings to increase paint film thickness.

Appendix A—Reference Methods

3. Method 24 (Candidate 1), Method 24 (Candidate 2), and Method 25 are added to Appendix A as follows:

* * * * *

Method 24 (Candidate 1)—Determination of Volatile Content (as Carbon) of Paint, Varnish, Lacquer, or Related Products

1 Applicability and Principle

1.1 Applicability. This method is applicable for the determination of volatile content (as carbon) of paint, varnish, lacquer, and related products listed in Section 2.

1.2 Principle. The weight of volatile carbon per unit volume of solids is calculated for paint, varnish, lacquer, or related surface coating after using standard methods to determine the volatile matter content, density of the coating, density of the solvent, and using the oxidation-nondispersive infrared (NDIR) analysis for the carbon content.

2. Classification of Surface Coating

For the purpose of this method, the applicable surface coatings are divided into two classes. They are:

2.1 Class I: General Solvent-Type Paints and Water Thinned Paints. This class includes white linseed oil outside paint, white soya and phthalic alkyd enamel, white linseed o-phthalic alkyd enamel, red lead primer, zinc chromate primer, flat white inside enamel, white epoxy enamel, white vinyl toluene, modified alkyd, white amino modified baking enamel, and other solvent-type paints not included in class II. It also includes emulsion or latex paints and colored enamels.

2.2 Class II: Varnishes and Lacquers. This class includes clear and pigmented lacquers and varnishes.

3 Applicable Standard Methods

Use the apparatus, reagents, and procedures specified in the standard methods below:

3.1 ASTM D 1644–59 Method A: Standard Methods of test for Non-volatile Contents of Varnishes. Do not use Method B.

3.2 ASTM D 1475–60. Standard Method of Test for Density of Paint, Lacquer, and Related Products.

3.3 ASTM D 2369–73: Standard Method of Test for Volatile Content of Paints.

3.4 ASTM D 3272–76: Standard Recommended Practice for Vacuum Distillation of Solvents from Solvent-Base Paints for Analysis.

4. Apparatus (Oxidation/NDIR Procedure)

4.1 Electric Furnace. Capable of maintaining a temperature of 800 ± 50° C.

4.2 Combustion Chamber. Stainless steel tubing, 13 mm (½ in.) internal diameter and 46 cm (18 in.) in length. Pack the tube loosely with 3 mm (⅛ in.) alumina pellets coated with 5 percent palladium. Place plugs of stainless steel wool at either end. Other catalytic systems which can demonstrate 95 percent efficiency as described in Section 6.5.4 are considered equivalent.

4.3 Septum. Teflon [1]-coated rubber septum.

4.4 Condenser. Ice bath condenser.

4.5 Analyzer. Nondispersive infrared analyzer (NDIR) to measure CO_2 **TO WITHIN ◇5 PERCENT OF THE CALIBRATION GAS CONCENTRATION.**

4.6 Recorder. Capable of matching the output of the NDIR.

4.7 Collection Tank. A collection tank of at least 6 liters in volume. See procedure in Section 6.5.1 for calibrating the volume of the tank. The tank should be capable of

[1] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

withstanding a pressure of 2000 mm (80 in.) Hg (gauge).

4.8 Pressure Gauge for Collection Tank. Capable of measuring positive pressure to 1100 mm (42 in.) Hg and vacuum pressure to 700±5 mm (28±0.25 in.) Hg.

4.9 Vacuum Pump. Capable of evacuating the collection tank to an absolute pressure of 51 mm (2 in.) Hg.

4.10 Analytical Balance. To measure to within ±0.5 mg.

4.11 Syringes. 100±1.0 µl, 500±1.0 µl, and 1000±5 µl syringe, with needles long enough to inject sample directly into the carrier gas stream.

4.12 Mixer. Vortex-mixer to ensure homogeneous mixing of solvent.

4.13 Flow Regulators. Rotameters, or equivalent, to measure to 500 cc/min in flow-rate.

4.14 Temperature Gauge. A thermometer graduated in 0.1° C, with range from 0° C to 100° C.

4.15 Tank Calibration Equipment. A balance to weigh collection tank to ±30 g or a graduated glass cylinder to measure tank volume within ±30 ml.

5. Reagents (Oxidation/NDIR Procedure)

5.1 Calibration Gases.

5.1.1 Zero Gas. Nitrogen.

5.1.2 CO_2 Gas. A range of concentration to allow at least a 3-point calibration of each measuring range of the instrument.

5.1.3 Carrier Gas. Air containing less than 1 ppm hydrocarbon as carbon, as certified by the manufacturer.

5.2 Catalyst. Alumina (3 mm pellets) coated with 5 percent palladium, or equivalent (commercially available).

5.3 Acetone. Reagent grade.

5.4 Nitric Acid Solution. Dilute 70 percent nitric acid 1:1 by volume with distilled water.

5.5 1-Butanol. Ninety-nine molecular percent pure.

5.6 Methane Gas 0.5 percent methane in air

6 Procedure

6.1 Classification of Samples. Assign the coating to one of the two classes discussed in Section 2 above. Assign any coating not clearly belonging to Class II to Class I.

6.2 Volatile Content. Use one of the following methods to determine the volatile content according to the class of coating

6.2.1 Class I. Use the Procedure in ASTM D 2369–73 Record the following information:

W_1 = Weight of dish and sample, g.

W_2 = Weight of dish and sample after heating, g

S = Sample weight, g

Repeat the procedure for a total of three determinations for each coating Calculate the weight fraction of volatile matter W for each analysis as follows.

$$W = \frac{W_1 - W_2}{S}$$

Report the arithmetic average weight fraction $\bar{W}$ of the three determinations.

6.2.2 Class II. Use the procedure in ASTM D 1644–59 Method A; record the following information:

A = Weight of dish, g.

B = Weight of sample used, g.

C = Weight of dish and sample after heating, g.

Repeat the procedure for a total of three determinations for each coating. Calculate the weight fraction W of volatile content for each analysis as follows:

$$W = \frac{(A + B - C)}{B}$$

Report the arithmetic average weight fraction $\bar{W}$ of three determinations.

6.3 Coating Density. Determine the density D_m (in g/cm³) of the paint, varnish, lacquer, or related product of either class according to the procedure outlined in ASTM D 1475–60. Make a total of three determinations for each coating. Report the density $\bar{D}_m$ as the arithmetic average of the three determinations.

6.4 Solvent Density.

6.4.1 Perform the solvent extraction according to the procedure outlined in ASTM D 3272–76. For aqueous paint, use a collection-tube in an ice-bath prior to the collection-tube in the acetone and dry-ice mixture to prevent water from freezing in the collection-tube Combine the contents of both tubes before analysis. If excessive foaming occurs during distillation, discard the sample, and repeat with a new sample treated with an anti-foam spray (e.g Dow Corning's "Anti-foam A Spray) before distillation. Anti-foam spray must be nonorganic and nonflammable. Use spray sparingly.

6.4.2 Determine the density D_s (in g/cm³) of the solvent according to the procedure outlined in ASTM D 1475–60 Make a total of three determinations for the solvent, and report the average density $\bar{D}_s$ as the arithmetic average of the three determinations.

6.5 Carbon Content of the Solvent. Analyze the solvent within 24 hours after distillation; keep it under refrigeration when not in use. To determine the carbon content, follow the procedure below:

6.5.1 Clean and calibrate the collection tank as follows Rinse the inside of the tank once with acetone, twice with tap water, thrice with the nitric acid solution, and twice with tap water. Weigh the tank when empty and when full of water. Measure the temperature of the water, and calculate the volume as follows

$$V = \frac{W_f - W_e}{D_t}$$

Where

t = Temperature of the water, °C (°F)

V = Volume of the tank, ml.

W_e = Weight of the empty tank, g.

W_f = Weight of the full tank, g.

D_t = Density of water at temperature t, g/ml

Alternatively, measure the volume of water necessary to fill the tank. The volume of the tank connections and pressure gauge are negligible for a tank volume of at least 6 liters

6.5.2 Calibrate the NDIR according to the manufacturer's instruction. Use at least a 3-point calibration. Introduce the CO_2 calibration gas through the analysis line.

6.5.3 Assemble the oxidation system as shown in Figure 1. Heat the catalyst until the temperature reaches equilibrium at 800 ±50° C. Add ice to the condenser and remove excess water to maintain the temperature at 0° C.

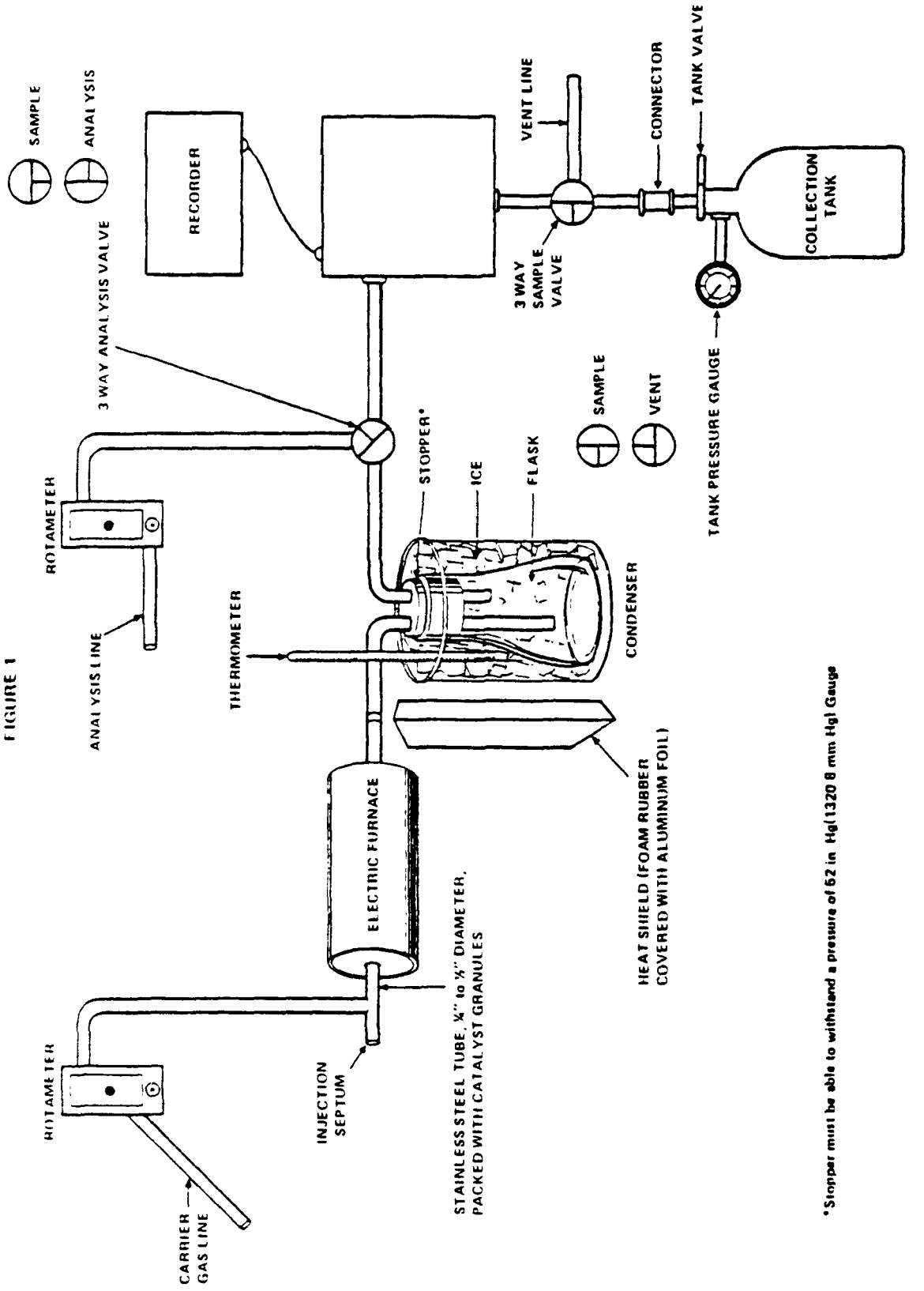


FIGURE 1

*Stopper must be able to withstand a pressure of 62 in Hg(1320.8 mm Hg) Gauge

6.5.4 Determination of Conversion Efficiency. Pass 0.5 percent methane gas in air through carrier gas line; 0.5 percent CO_2 should be generated within ±5 percent error. Using a 100 μl sample of l-butanol, follow the procedure in 6.5.5 to 6.5.13. Calculate the theoretical CO_2 volume percent as in Section 7.3. This value should equal the value as measured by the NDIR, within ±5 percent error. If conversion efficiency is 100 ±5 percent, analyze the solvent extracted from the paint according to procedure in Sections 6.5.5 to 6.5.14.

6.5.5 Purge the collection tank twice with N_2, then evacuate the tank to at least 50.8 mm (2 in.) Hg absolute pressure. Connect the cylinder to the collection line.

6.5.6 Mix the solvent sample thoroughly on a vortex-mixer. Then, draw a sample (0.100 to 0.300 ml) into the syringe. Record the volume of sample used.

6.5.7 Turn analysis valve to "sample" position, and turn the sample valve to "vent" position. Then turn on the carrier gas at a rate of 500 cc/min to flush the system for 2 minutes.

6.5.8 With gas flowing at 500 cc/min (maintain this rate throughout the test procedure), turn sample valve to "sample" position. Open the tank valve and inject the sample into the gas stream through the injection septum. Continue to draw the sample into the tank until the NDIR reads zero. (Note.— On replicate samples, a decrease in peak value indicates that the catalyst or sample has deteriorated, assuming that other factors, such as leaks, cell contamination, mechanical defects of the instruments, etc., have not occurred.)

6.5.9 At completion of collection, close the tank valve, and turn sample valve to "vent" position. Let the carrier gas flush the system for 2 minutes, then turn off the carrier gas.

6.5.10 Disconnect the tank and pressurize it with N_2 to about 1016 mm (40 in.) Hg gauge pressure. Record the final tank pressure after pressurization, the atmospheric pressure, and the room temperature.

6.5.11 Connect the tank to the analysis line and turn the analysis valve to "analysis" position.

6.5.12 Pass the CO_2 sample gas at the same rate as the calibration gas. Keep the rate constant by adjusting the rotameter as tank pressure falls.

6.5.13 Record the CO_2 concentration when the peak value is reached. This peak value will remain constant as long as the sample gas continues to flow at a constant rate.

6.5.14 Repeat steps 6.5.5 through 6.5.13 until three consecutive results are obtained which differ from one another in value by no more than ±5 percent. At the end of the third test, check the catalyst function by passing the collected sample gas through the catalyst and into the NDIR. No increase in concentration value should occur. If the concentration is higher, invalidate the test series, replace the catalyst and repeat the test.

6.5.15 Report the results as an arithmetic average of the three determinations.

7. Calculations. Carry out the calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after decimal calculation.

7.1 Nomenclature.

C_c = Volatile matter content as carbon per unit volume of paint solids, g/l (lb/gal).
D_b = Density of l-Butanol, g/cm³.
D_m = Average coating density, g/cm³ (See Section 6.3).
D_s = Average solvent density, g/cm³ (See Section 6.4).
L_b = Volume of l-Butanol used in the test, cm³.
L_s = Volume of paint solvent used in the test, cm³.
74.12 = Molecular weight of l-Butanol.
M_c = Mass of carbon, g.
4 = Number of carbon atoms in l-Butanol.
P_{std} = Absolute standard pressure, 760 mm Hg (29.92 in. Hg).
P_f = Absolute final tank pressure after pressurization, mm Hg (in. Hg).
T_{std} = Absolute standard temperature, 293° K (528° R).
T_t = Absolute tank temperature, °K (°R).
%Solv. = Volume percent of solvent in paint coating.
V_{co_2} = Volume of CO_2 in liters, at standard temperature and pressure.
V_{gs} = Total gas volume, corrected to standard conditions, in liters.
V_{pc} = Volume percent of CO_2.
V_t = Volume of tank, liters.
W = Weight fraction of volatile matter content.

7.2 Total Gas Volume, Corrected to Standard Conditions.

$$V_{gs} = \frac{T_{std}}{P_{std}} \frac{P_f}{T_t} V_t = K_1 \frac{P_f}{T_t} V_t \qquad \text{Equation 1}$$

Where:
K_1 = 17.65 for English units.
K_1 = 0.3855 for Metric units.

7.3 Volume Percent of CO_2 From l-Butanol:

$$V_{pc} = \frac{1.298 L_b D_b}{V_{gs}} \qquad \text{Equation 2}$$

7.4 Mass of Carbon

$$M_c = V_{pc} V_{gs} \frac{12.0}{24.056} \frac{1}{100} \qquad \text{Equation 3}$$

7.5 Percent Volume Solvent in Paint.

$$\%Solv. = W \frac{D_m}{D_s} (100) \qquad \text{Equation 4}$$

7.6 Volatile Matter Content as Carbon.

$$C_c = K_2 \left[\frac{M_c}{L_s}\right] \frac{\%Solv.}{100 - \%Solv.} \qquad \text{Equation 5}$$

Where:
K_2 = 8.3445 for English units.
K_2 = 1000 for Metric units.

8. Bibliography.

8.1 Standard Methods of Test for Nonvolatile Content of Varnishes. In: 1974 Book of ASTM Standards, Part 27. Philadelphia, Pennsylvania, ASTM Designation D 1644–59. 1974. p. 285–286.

8.2 Standard Method of Test for Volatile Content of Paints. In: 1978 Book of ASTM Standards, Part 27. Philadelphia, Pennsylvania. ASTM Designation D 2369–73. 1978. p. 431–432.

8.3 Standard Method of Test for Density of Paint, Varnish, Lacquer, and Related Products. In: 1974 Book of ASTM Standards, Part 25. Philadelphia, Pennsylvania, ASTM Designation D 1476–60. 1974. p. 231–233.

8.4 Standard Recommended Practice for Vacuum Distillation of Solvents from Solvent-Base Paints for Analysis. In: 1978 Annual Book of ASTM Standards, Part 27. Philadelphia, Pennsylvania, ASTM Designation D 3272076. 1978. p. 612–614.

8.5 Salo, Albert E., William L. Oaks, and Robert D. MacPhee. Total Combustion Analysis. Air Pollution Control District-County of Los Angeles. August 1974.

Method 24 (Candidate 2)— Determination of Volatile Organic Compound Content (as Mass) of Paint, Varnish, Lacquer, or Related Products

1. *Applicability and Principle.*

1.1 Applicability. This method applies to the determination of volatile organic compound content (as mass) of paint, varnish, lacquer, and related products listed in Section 2.

1.2 Principle. Standard methods are used to determine the volatile matter content, density of the coating, volume of solid, and water content of the paint, varnish, lacquer, and related surface coating. From this information, the mass of volatile organic compounds per unit volume of solids is calculated.

2. *Classification of Surface Coating.* For the purpose of this method, the applicable surface coatings are divided into three classes. They are:

2.1 Class I: General Solvent Reducible Paints. This class includes white linseed oil outside paint, white soya and phthalic alkyd enamel, white linseed o-phthalic alkyd enamel, red lead primer, zinc chromate primer, flat white inside enamel, white epoxy enamel, white vinyl toluene, modified alkyd, white amino modified baking enamel, and other solvent-type paints not included in Class II.

2.2 Class II: Varnishes and Lacquers. This class includes clear and pigmented lacquers and varnishes.

2.3 Class III. This class includes all water reducible paints.

3. *Applicable Standard Methods.* Use the apparatus, reagents, and procedures specified in the standard method below:

3.1 ASTM D 1644–75 Method A: Standard Method of Test for Non-volatile Contents of Varnishes. Do not use Method B.

3.2 *ASTM D 1475–60. Standard Method of* Test for Density of Paint, Lacquer, and Related Products.

3.3 ASTM D 2369–73. Standard Method of Test for Volatile Content of Paints.

3.4 ASTM D 2697–73. Standard Method of Test for Volume Non-volatile Matter in Clear or Pigmented Coatings.

3.5 *ASTM D 3792. Standard Method of* Test for Water in Water Reducible Paint by Direct Injection into a Gas Chromatograph.

3.6 ASTM Draft Method of Test for Water in Paint or Related Coatings by the Karl Fischer Titration Method.

4. *Procedure.*

4.1 Classification of Samples. Assign the coating to one of the three classes discussed in Section 2 above. Assign any coating not clearly belonging to Class II or III to Class I.

4.2 Non-Aqueous Volatile Content. Use one of the following methods to determine the non-aqueous volatile content according to the class of coating.

4.2.1 Class I. Use the procedure in ASTM D 2369–73; record the following information:

W_1 = Weight of dish and sample, g.

W_2 = Weight of dish and sample after heating g.

S = Sample of weight, g.

Repeat the procedure for a total of three determinations for each coating. Calculate the weight fraction of non-aqueous volatile matter W_v for each analysis as follows:

$$W_v = \frac{W_1 - W_2}{S}$$

Report the arithmetic average weight fraction W_v of the three determinations.

4.2.2 Class II. Use the procedure in ASTM D 1644–75 Method A, record the following information:

A = Weight of dish, g.

B = Weight of sample used, g.

C = Weight of dish and sample after heating, g.

Repeat the procedure for a total of three determinations for each coating. Calculate the weight fraction W_v of non-aqueous volatile content for each analysis as follows:

$$W_v = \frac{(A + B - C)}{B}$$

Report the arithmetic average weight fraction W_v of the three determinations

4.2.3 Class III.

4.2.3.1 Water Content. Determine the water content (in % H_2O) of the coating according to either "Provisional Method of Test for Water in Water Reducible Paint by Direct Injection into a Gas Chromatograph" or "Provisional Method of Test for Water in Paint or Related coatings by the Karl Fischer Titration Method." Repeat the procedure for a total of three determinations for each coating. Report the arithmetic average weight percent % H_2O of the three determinations.

4.2.3.2 Volatile Content (Including Water). Use the procedure in ASTM D 2369–73; record the following information:

W_1 = Weight of dish and sample, g.

W_2 = Weight of dish and sample after heating, g

S = Sample weight, g.

Repeat the procedure for a total of three determinations for each coating. Calculate the weight fraction of volatile matter as follows

$$V = \frac{W_1 - W_2}{S}$$

Report the arithmetic average weight fraction V of the three determinations.

4.2.3.3 Non-Aqueous Volatile Matter. Calculate the average non-aqueous volatile matter W_v as follows:

$$\bar{W}_v = \bar{V} - \frac{\overline{\% H_2O}}{100}$$

4.3 Coating Density. Determine the density D_m (in g/cm³) of the paint, varnish, lacquer, or related product of any class according to the procedure outlined in ASTM D 1475–60. Make a total of three determinations for each coating. Report the density D_m as the arithmetic average of the three determinations.

4.4 Non-Volatile Content. Determine the volume fraction of the non-volatile matter of the coating of any class according to the procedure outlined in ASTM D 2697–73. Calculate the volume fraction P_n of non-volatile matter as follows:

$$P_n = \frac{\% \text{ Volume Nonvolatile Matter}}{100}$$

Make a total of three determinations for each coating. Report the arithmetic average volume fraction P_n of the three determinations.

5. *Volatile Organic Compounds Content.* Calculate the volatile organic compound content C_m in terms of mass per volume of solids (g/liter) as follows

$$C_m = \frac{\bar{W}_v \bar{D}_m}{\bar{P}_n}$$

To convert g/liter to lb/gal, multiply C_m by 8.3455×10^{-3}.

6. *Bibliography*

6.1 Standard Methods of Test of Nonvolatile Content of Varnishes. In. 1974 Book of ASTM Standards, Part 27, Philadelphia, Pennsylvania, ASTM Designation D 1644–75. 1978. p 288–289.

6.2 Standard Method of Test for Volatile Content of Paints. In: 1978 Book of ASTM Standards, Part 27. Philadelphia, Pennsylvania, ASTM Designation D 2369–73. 1978 p. 431–432.

6.3 Standard Method of Test for Density of Paint, Varnish, Lacquer, and Related Products. In. 1974 Book of ASTM Standards, Part 25 Philadelphia, Pennsylvania, ASTM Designation D 1476–60. 1974. p. 231–233.

6.4 Standard Method of Test for Water in Water Reducible Paint by Direct Injection into a Gas Chromatograph. Available from: Chairman, Committee D–1 on Paint and Related Coatings and Materials, American Society for Testing and Materials, 1916 Race St., Philadelphia, PA 19103. ASTM Designation D 3792.

6.5 Draft method of Test for Water in Paint or Related Coatings by the Karl Fischer Titration Method. Available from: Chairman, Committee D–1 on Paint and Related Coatings and Materials, American Society for Testing and Materials, 1916 Race St., Philadelphia, PA 19103.

Method 25—Determination of Total Gaseous Nonmethane Organic Emissions as Carbon: Manual Sampling and Analysis Procedure

1. Principle and Applicability.

1.1 Principle. An emission sample is anisokinetically drawn from the stack through a chilled condensate trap by means of an evacuated gas collection tank. Total gaseous nonmethane organics (TGNMO) are determined by combining the analytical results obtained from independent analyses of the condensate trap and evacuated tank fractions. After sampling is completed, the organic contents of the condensate trap are oxidized to carbon dioxide which is quantitatively collected in an evacuated vessel; a portion of the carbon dioxide is reduced to methane and measured by a flame ionization detector (FID) A portion of the sample collected in the gas sampling tank is injected into a gas chromatographic (GC) column to achieve separation of the nonmethane organics from carbon monoxide, carbon dioxide and methane; the nonmethane organics are oxidized to carbon dioxide, reduced to methane, and measured by a FID

1.2 Applicability. This method is applicable to the measurement of total gaseous nonmethane organics in source emissions.

2. Apparatus.

2.1 General. TGNMO sampling equipment can be constructed by a laboratory from commercially available components and components fabricated in a machine shop The primary components of the sampling system are a condensate trap, flow control system, and gas sampling tank (Figure 1). The analytical system consists of two major subsystems, an oxidation system for recovery of the sample from the condensate trap and a TGNMO analyzer. The TGNMO analyzer is a FID preceded by a reduction catalyst, oxidation catalyst, and GC column with backflush capability (Figures 2 and 3). The system for the removal and conditioning of the organics captured in the condensate trap consists of a heat source, oxidation catalyst, nondispersive infrared (NDIR) analyzer and an intermediate gas collection tank (Figure 4).

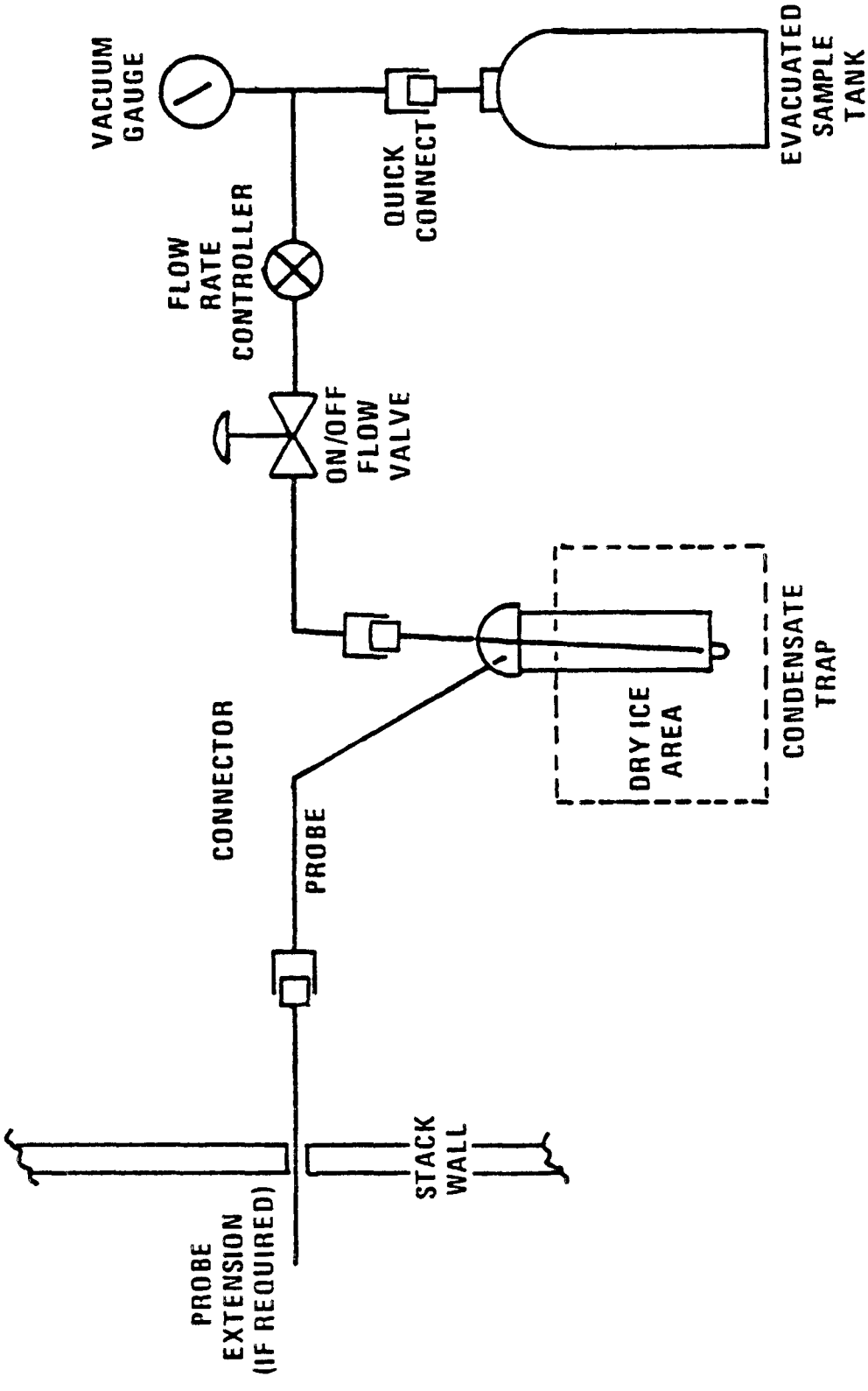


Figure 1. Sampling apparatus.

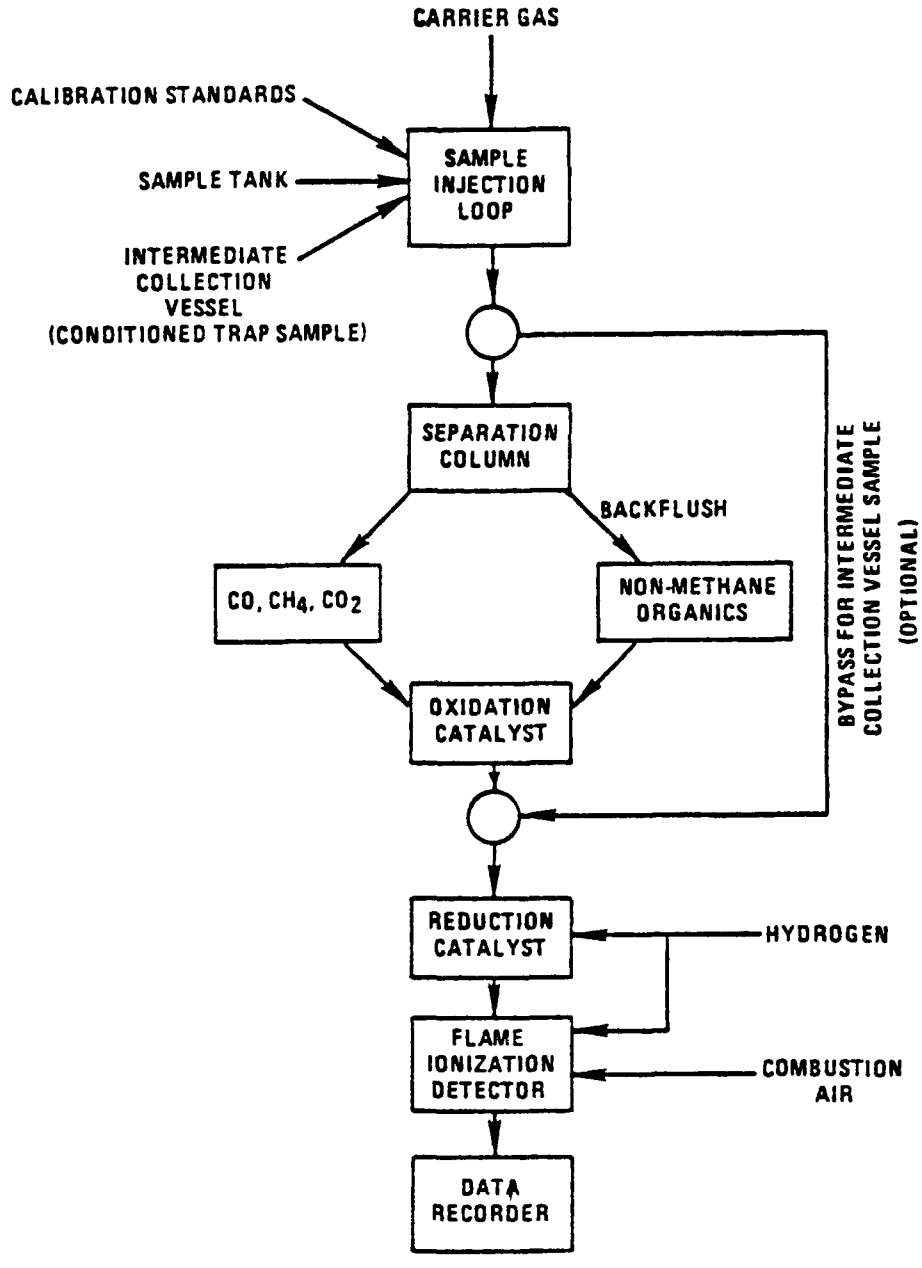


Figure 2. Simplified schematic of total gaseous non-methane organic (TGNMO) analyzer.

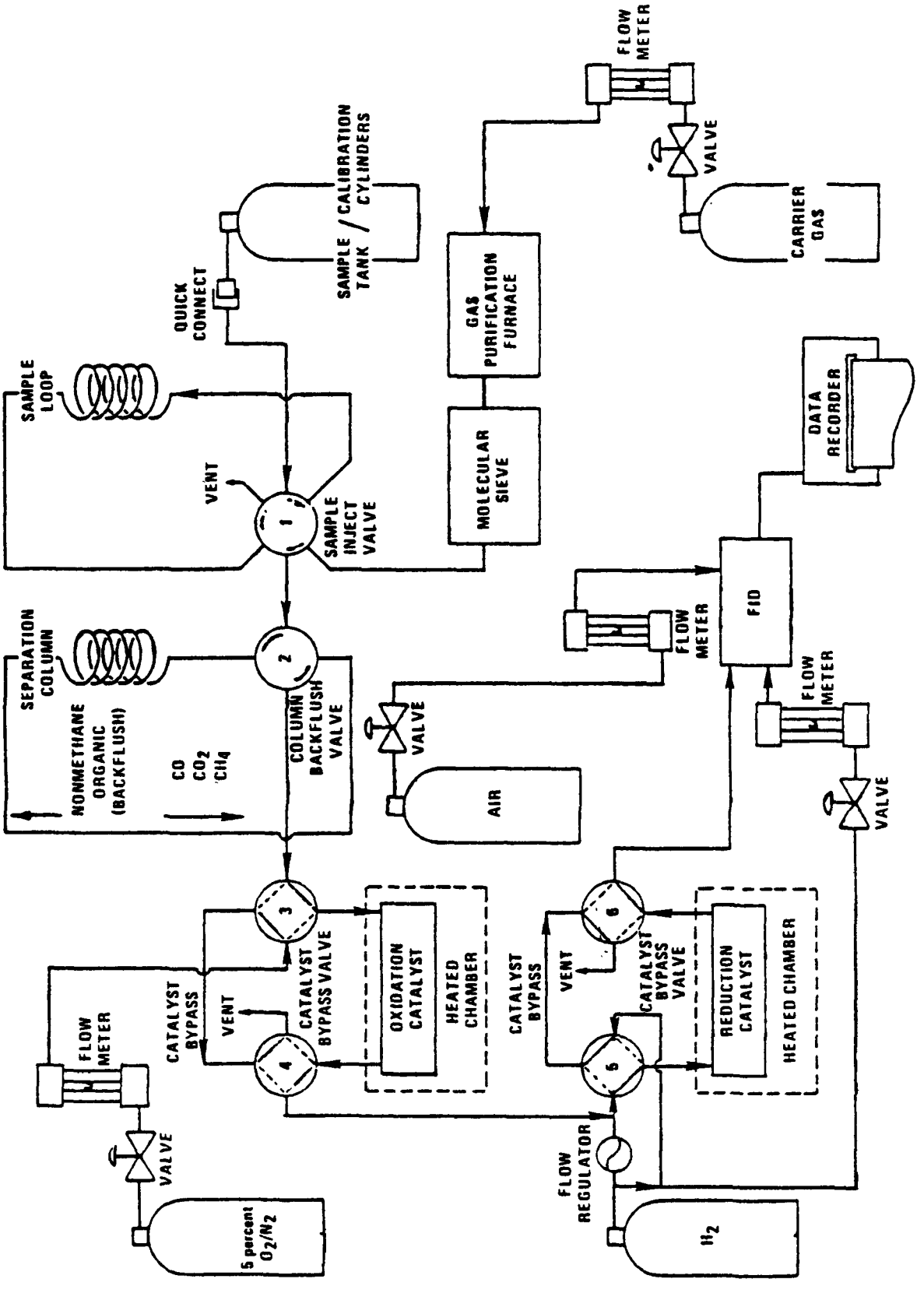


Figure 3 Total gaseous nonmethane organic (TGNMO) analyzer.

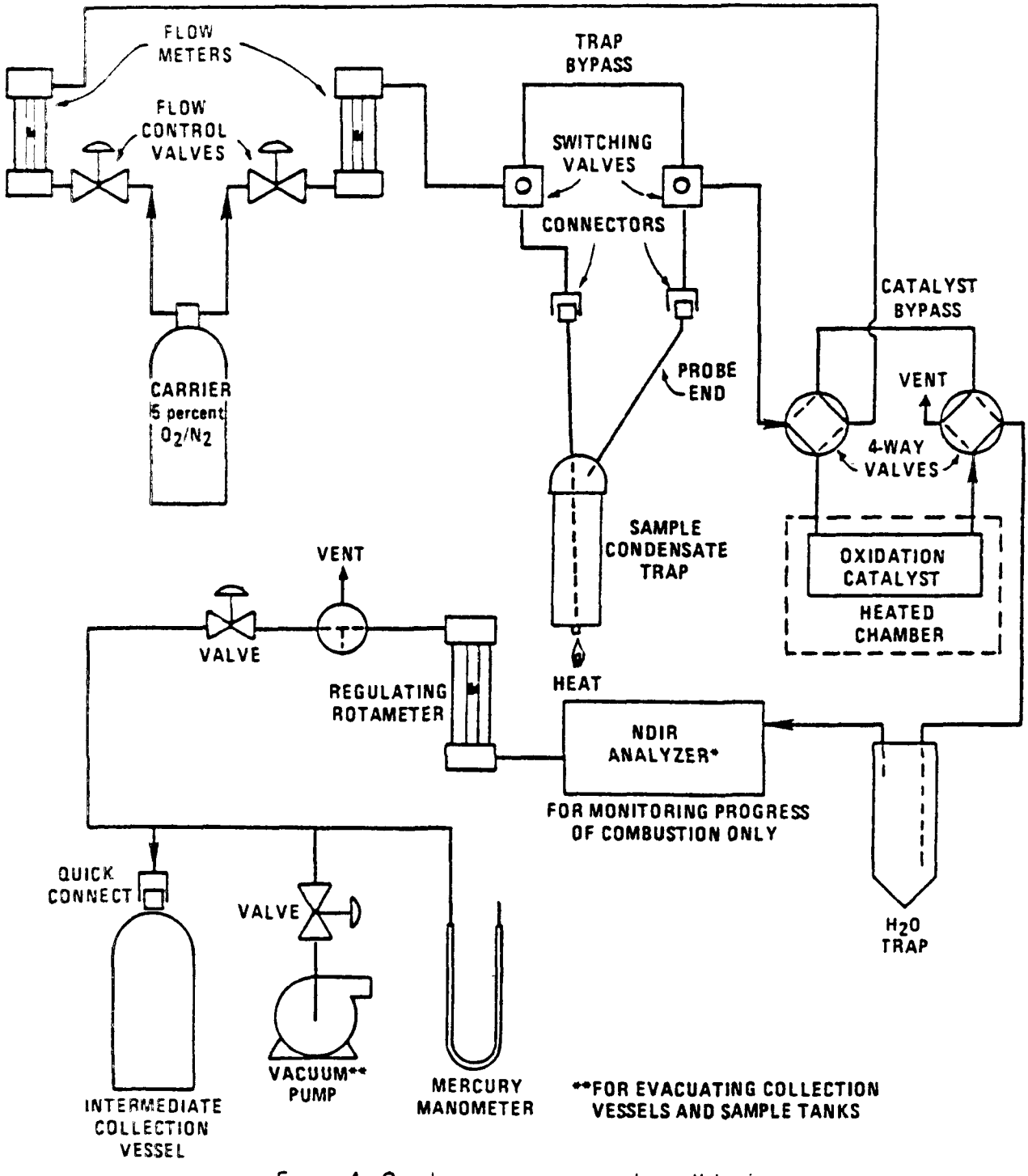


Figure 4. Condensate recovery and conditioning apparatus.

2.2 Sampling.
2.2.1 Probe. ⅛" stainless steel tubing.
2.2.2 Condensate Trap. The condensate trap shall be constructed of 316 stainless steel; construction details of a suitable trap are shown in Figure 5.
2.2.3 Flow Shut-off Valve. Stainless steel control valve for starting and stopping sample flow.
2.2.4 Flow Control System. Any system capable of maintaining the sampling rate to within ±10 percent of the selected flow rate (50—100 cc/min. range).
2.2.5 Vacuum Gauge. Vacuum gauge calibrated in mm Hg. for monitoring the vacuum of the evacuated sampling tank during leak checks and sampling
2.2.6 Gas Collection Tank. Stainless steel or aluminum tank with a volume of 4 to 8 liters. The tank is fitted with a stainless steel female quick connect for assembly to the sampling train and analytical system.
2.2.7 Mercury manometer. U-tube mercury manometer capable of measureing pressure to within 1.0 mm Hg in the 0/900 mm range.
2.2.8 Vacuum Pump. Capable of pulling a vacuum of 700 mm Hg.
2.3 Analysis. For analysis, the following equipment is needed.
2.3.1 Condensate Recovery and Conditioning Apparatus (Figure 4).
2.3.1.1 Heat Source. A heat source sufficient to heat the condensate trap to a temperature just below the point where the trap turns a "cherry red" color is required. An electric muffle-type furnace heated to 600° C is recommended.
2.3.1.2 Oxidizing Catalyst. Inconel tubing packed with an oxidizing catalyst capable of meeting the catalyst efficiency criteria of this method (Section 4.4.2).
2.3.1.3 Water Trap. Any leak proof moisture trap capable of removing moisture from the gas stream may be used.
2.3.1.4 NDIR Detector. A detector capable of indicating CO_2 concentration in the zero to 5 percent range. This detector is required for monitoring the progress of combustion of the organic compounds from the condensate trap.
2.3.1.5 Pressure Regulator. Stainless steel needle valve required to maintain the NDIR detector cell at a constant pressure.
2.3.1.6 Intermediate Collection Tank. Stainless steel or aluminum collection vessel. Tanks with nominal volumes in the 1 to 4 liter range are recommended. The end of the tank is fitted with a female quick connect.
2.3.2 Total Gaseous Nonmethane Organic (TGNMO) Analyzer. Semi-continuous GC/FID analyzer capable of: (1) separating CO, CO_2, and CH_4 from nonmethane organic compounds, and (2) oxidizing the non-methane organic compounds to CO_2, reducing the CO_2 to methane, and quantifying the methane. The analyzer shall be demonstrated prior to initial use to be capable of proper separation, oxidation, reduction, and measurement. As a minimum, this demonstration shall include measurement of a known TGNMO concentration present in a mixture that also contains CH_4, CO, and CO_2 (see paragraph 4.4.1).
2.3.2.1 The TGNMO analyzer consists of the following major components.
2.3.2.1.1 Oxidation Catalyst. Inconel tubing packed with an oxidation catalyst capable of meeting the catalyst efficiency criteria of paragraph 4.4.1.2.
2.3.2.1.2 Reduction Catalyst. Inconel tubing packed with a reduction catalyst capable of meeting the catalyst efficiency criteria of paragraph 4.4.1.3.
2.3.2.1.3 Separation Column. A gas chromatographic column capable of separating CO, CO_2, and CH_4 from nonmethane organic compounds. The specified column is as follows: ⅛ inch O.D. stainless steel packed with 3 feet of 10 percent methyl silicone, Sp 2100* (or equivalent) on Supelcoport* (or equivalent), 80/100 mesh, followed by 1.5 feet porapak Q* (or equivalent) 60/80 mesh. The inlet side is to the silicone.
Other columns may be used subject to the approval of the Administrator. In any event, proper separation shall be demonstrated according to the procedures of paragraph 4.4.1.4.
2.3.2.1.4 Sample Injection System. A gas chromatographic sample injection valve with sample loop sized to properly interface with the TGNMO system.
2.3.2.1.5 Flame Ionization Detector (FID). A flame ionization detector meeting the following specifications is required:
2.3.2.1.5.1 Linearity. A linearity of ±5 percent of the expected value for each full scale setting up to the maximum percent absolute (methane or carbon equivalent) calibration point is required. The FID shall be demonstrated prior to initial use to meet this specification through a 5-point (minimum) calibration. There shall be at least one calibration point in each of the following ranges: 5–10, 50–100, 500–1,000, 5,000–10,000, and 40,000–100,000 ppm (methane or carbon equivalent). Certification of such demonstration by the manufacturer is acceptable. An additional linearity performance check (see Section 4.4.1.1) must be made before each use (i.e., before each set of samples is analyzed or daily whichever occurs first).
2.3.2.1.5.2 Range. Signal attenuators shall be available so that a minimum signal response of 10 percent of full scale can be produced when analyzing calibration gas or sample.
2.3.2.1.5.3 Sensitivity. The detector sensitivity shall be equal to or better than 2.0 percent of the full scale setting, with a minimum full scale setting of 10 ppm (methane or carbon equivalent)
2.3.2.1.6 Data Recording System Analog strip chart recorder or digital integration system for permanently recording the analytical results.
2.3.3 Mercury Manometer. U-tube mercury manometer capable of measuring pressure to within 1.0 mm Hg in the 0–900 mm range.
2.3.4 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 1 mm.
2.3.5 Vacuum Pump. Laboratory vacuum pump capable of evacuating the sample tanks to an absolute pressure of 5 mm Hg.
3. Reagents.
3.1 Sampling.
3.1.1 Crushed Dry Ice.
3.2 Analysis.
3.2.1 TGNMO Analyzer.
3.2.1.1 Carrier Gas. Pure helium, containing less than 1 ppm organics.
3.2.1.2 Fuel Gas. Pure Hydrogen, containing less than 1 ppm organics.
3.2.2 Condensate Recovery and Conditioning Apparatus.
3.2.2.1 Carrier Gas. Five percent O_2 in N_2, containing less than 1 ppm organics.
3.3 Calibration For all calibration gases, the manufacturer must recommend a maximum shelf life for each cylinder so that the gas concentration does not change more than ±5 percent from its certified value The date of gas cylinder preparation, certified organic concentration and recommended maximum shelf life must be affixed to each cylinder before shipment from the gas manufacturer to the buyer.
3.3.1 TGNMO Analyzer
3.3.1.1 Oxidation Catalyst Efficiency Check. Gas mixture standard with nominal concentration of 5 percent methane and 5 percent oxygen in nitrogen.
3.3.1.2 Reducation Catalyst Efficiency Check. Gas mixture standard with nominal concentration of 5 percent CO_2 in air.
3.3.1.3 Flame Ionization Detector Linearity Calibration Gases (3). Gas mixture standards with known methane (CH_4) concentrations in the 5–10 ppm, 500–1,000 ppm, and 5–10 percent range, in air. These gas standards are to be used to check the FID linearity as described in Section 4.4.1.1.
3.3.1.4 System Operation Standards (2). These calibration gases are required

*Mention of trade name does not constitute endorsement.

to check the total system operation as specified in Section 4.4.1.4. Two gas mixtures are required:

3.3.1.4.1 Gas mixture standard containing (nominal) 50 ppm CO, 50 ppm CH_4, 2 percent CO_2, and 15 ppm C_3H_8, prepared in air.

3.3.1.4.2 Gas mixture standard containing (nominal) 50 ppm CO, 50 ppm CH_4, 2 percent CO_2, and 1,000 ppm C_3H_8, prepared in air.

3.3.2 Condensate Recovery and Conditioning Apparatus. The calibration gas specified in paragraph 3.3.1.1 is required for performing an oxidation catalyst check according to the procedure of paragraph 4.4.2.

4. *Procedure.*

4.1 Sampling.

4.1.1 Sample Tank Evacuation. Either in the laboratory or in the field, evacuate the sample tank to 5 mm Hg absolute pressure or less (measured by a mercury U-tube manometer). Record the temperature, barometric pressure, and tank vacuum as measured by the manometer.

4.1.2 Sample Tank Leak Check. Leak check the gas sample tank immediately after the tank is evacuated. Once the tank is evacuated, allow the tank to sit for 30 minutes. The tank is acceptable if no change in tank vacuum (measured by the mercury manometer) is noted.

4.1.3 Assembly. Just prior to assembly, use a mercury U-tube manometer to measure the tank vacuum. Record this vacuum (P_{ti}), the ambient temperature (T_{ti}), and the barometric pressure (P_{bi}) at this time. Assuring that the flow control valve is in the closed position, assemble the sampling system as shown in Figure 1. Immerse the condensate trap body in dry ice to within 1 or 2 inches of the point where the inlet tube joins the trap body.

4.1.4 Leak Check Procedures.

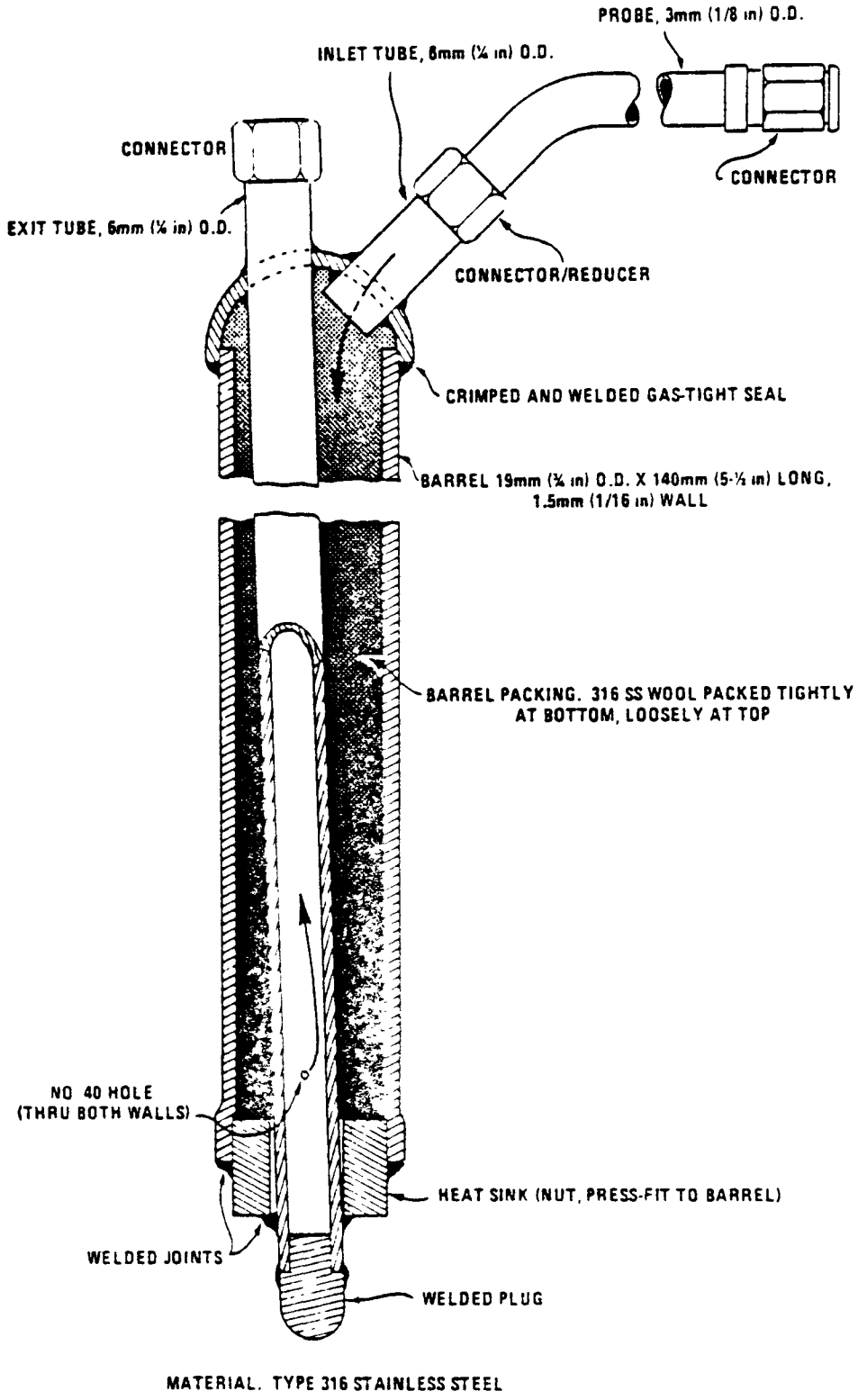


Figure 5. Condensate trap[2].

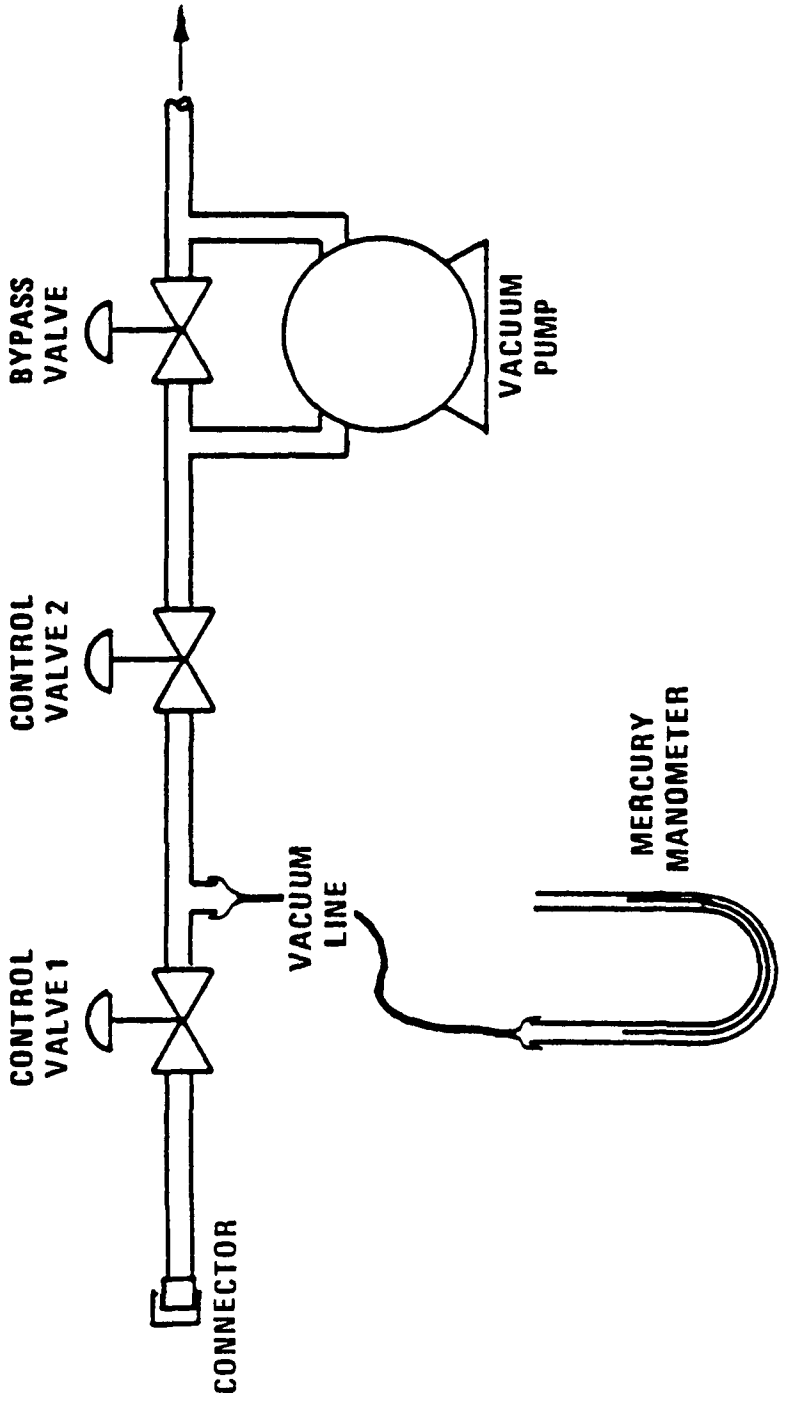


Figure 6. Leak check apparatus.

VOLATILE ORGANIC CARBON

FACILITY _____ SAMPLE LOCATION _____

LOCATION _____ OPERATOR _____

DATE _____ RUN NUMBER _____

TANK NUMBER _____ TRAP NUMBER _____ SAMPLE ID NUMBER _____

	TANK VACUUM, mm Hg	BAROMETRIC PRESSURE, mm Hg	AMBIENT TEMPERATURE, °C
PRETEST	(MANOMETER) _____ (GAUGE) _____		
POST TEST	(MANOMETER) _____ (GAUGE) _____		

LEAK RATE, mm Hg/5 min..	TANK	TRAP HALF
PRETEST		
POST TEST		

TIME CLOCK/SAMPLE	GAUGE VACUUM, mm Hg	FLOWMETER SETTING	COMMENTS

Figure 7. Example Field Data Form.

4.1.4.1 Pretest Leak Check. A pretest leak check is required. After the sampling train is assembled, record the tank vacuum as indicated by the vacuum gauge. Wait a minimum period of 15 minutes and recheck the indicated vacuum. If the vacuum has not changed, the portion of the sampling train behind the shut-off valve does not leak and is considered acceptable. To check the front portion of the sampling train, attach the leak check apparatus (Figure 6) to the probe tip. Evacuate the front half of the train (i.e., do not open the sampling train flow control valve) to a vacuum of at least 500 mm Hg. Close the shut-off valve on the leak check apparatus and record the vacuum indicated by the manometer on the data sheet (Figure 7). Allow the system to sit for 5 minutes and then recheck the vacuum. A change of less than 2 mm Hg for the 5-minute leak check period is acceptable Record the front half leak rate (mm Hg/5-minute period) on the data form. When an acceptable leak rate has been obtained disconnect the leak check apparatus from the probe tip.

4.1.4.2 Post Test Leak Check. A leak check is mandatory at the conclusion of each test run. After sampling is completed, attach the U-tube manometer to the probe tip; minimize the amount of flexible line used. Open the sample train flow control valve for a period of 2 minutes or until the vacuum indicated on the manometer stabilizes, whichever occurs first; shut off the sample train flow control valve. Record the vacuums indicated on the manometer (front half) and on the tank vacuum gauge (back-half). After 5 minutes, recheck these vacuum readings. A leak rate of less than 2 mm Hg per 5-minute period is acceptable for the front half; the back half portion is acceptable if no visible change in the tank vacuum gauge occurs Record the post test leak rate (mm Hg per 5 minutes), and then disconnect the manometer from the probe tip and seal the probe. If the sampling train does not pass the post test leak check, invalidate the run.

4.1.5 Sample Train Operation Place the probe into the stack such that the probe is perpendicular to the direction of stack gas flow; locate the probe tip at a single preselected point. For stacks having a negative static pressure, assure that the sample port is sufficiently sealed to prevent air in-leakage around the probe Check the dry ice level and add ice if necessary. Record the clock time and sample tank gauge vacuum. To begin sampling, open and adjust (if applicable) the flow control valve(s) of the flow control system utilized in the sampling train; maintain a constant flow rate (± 10 percent) throughout the duration of the sampling period. Record the gauge vacuum and flowmeter setting (if applicable) at 5-minute intervals. Select a total sample time greater than or equal to the minimum sampling time specified in the applicable subpart of the regulation; end the sampling when this time period is reached or when a constant flow rate can no longer be maintained. When the sampling is completed, close the gas sampling tank control valve. Record the final readings. Note: If the sampling had to be stopped before obtaining the minimum sampling time (specified in the applicable subpart) because a constant flow rate could not be maintained, proceed as follows: After removing the probe from the stack, remove the evacuated tank from the sampling train (without disconnecting other portions of the sampling train) and connect another evacuated tank to the sampling train. Prior to attaching the new tank to the sampling train, assure that the tank vacuum (measured on-site by the U-tube manometer) has been recorded on the data form and that the tank has been leak-checked (on-site). After the new tank is attached to the sample train, proceed with the sampling; after the required minimum sampling time has been exceeded, end the test.

4.2 Sample Recovery. After sampling is completed, remove the probe from the stack and seal the probe end. Conduct the post test leak check according to the procedures of paragraph 4.1.4.2. After the post test leak check has been conducted, disconnect the condensate trap at the flow metering system. Tightly seal the ends of the condensate trap; keep the trap packed in dry ice until analysis. Remove the flow metering system from the sample tank. Attach the U-tube manometer to the tank (keep length of flexible connecting line to a minimum) and record the final tank vacuum (P_t), record the tank temperature (T_t) and barometric pressure at this time. Disconnect the manometer from the tank. Assure that the test run number is properly identified on the condensate trap and evacuated tank(s)

4.3 Analysis

4.3.1 Preparation

4.3.1.1 TGNMO Analyzer. Set the carrier gas, air, and fuel flow rates and then begin heating the catalysts to their operating temperatures. Conduct the calibration linearity check required in paragraph 4.4.1.1 and the system operation check required in paragraph 4.4.1.4. Optional: Conduct the catalyst performance checks required in paragraphs 4.4.1.2 and 4.4.1.3 prior to analyzing the test samples

4.3.1.2 Condensate Recovery and Conditioning Apparatus. Set the carrier gas flow rate and begin heating the catalyst to its operating temperature. Conduct the catalyst performance check required in paragraph 4.4.2 prior to oxidizing any samples.

4.3.2 Condensate Trap Carbon Dioxide Purge and Evacuated Sample Tank Pressurization. The first step in analysis is to purge the condensate trap of any CO_2 which it may contain and to simultaneously pressurize the gas sample tank. This is accomplished as follows: Obtain both the sample tank and condensate trap from the test run to be analyzed. Set up the condensate recovery and conditioning apparatus so that the carrier flow bypasses the condensate trap hook-up terminals, bypasses the oxidation catalyst, and is vented to the atmosphere. Next, attach the condensate trap to the apparatus and pack the trap in dry ice. Assure that the valve isolating the collection vessel connection from the atmospheric vent is closed and then attach the gas sample tank to the system as if it were the intermediate collection vessel Record the tank vacuum on the laboratory data form. Assure that the NDIR analyzer indicates a zero output level and then switch the carrier flow through the condensate trap; immediately switch the carrier flow from vent to collect and open the valve to the tank. The condensate trap recovery and conditioning apparatus should now be set up as indicated in Figure 8. Monitor the NDIR; when CO_2 is no longer being passed through the system, switch the carrier flow so that it once again bypasses the condensate trap Continue in this manner until the gas sample tank is pressurized to a nominal gauge pressure of 800 mm mercury. At this time, isolate the tank, vent the carrier flow, and record the sample tank pressure (P_{tf}), barometric pressure (P_{bf}) and ambient temperature (T_{af}). Remove the gas sample tank from the system

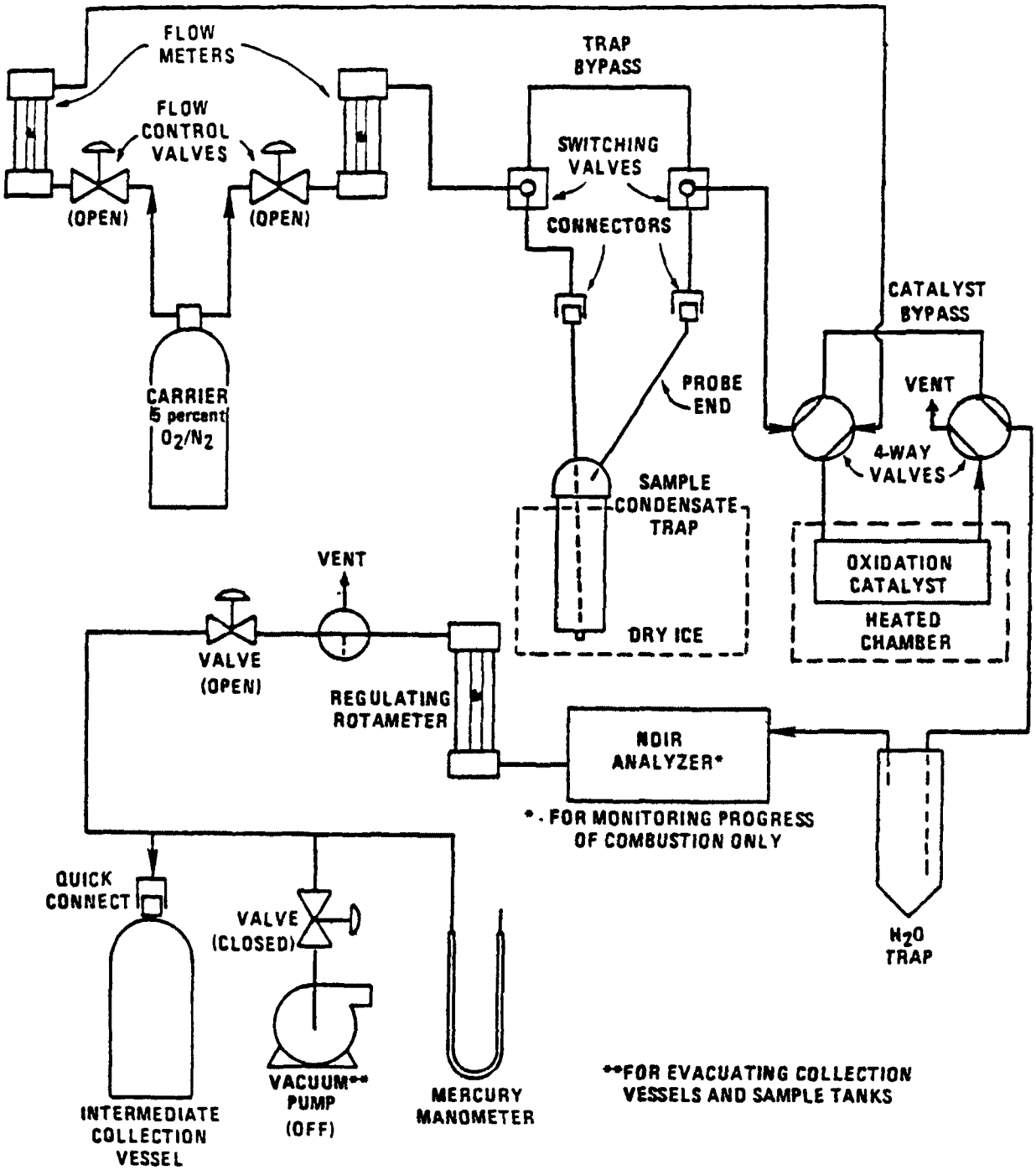


Figure 8. Condensate recovery and conditioning apparatus, carbon dioxide purge.

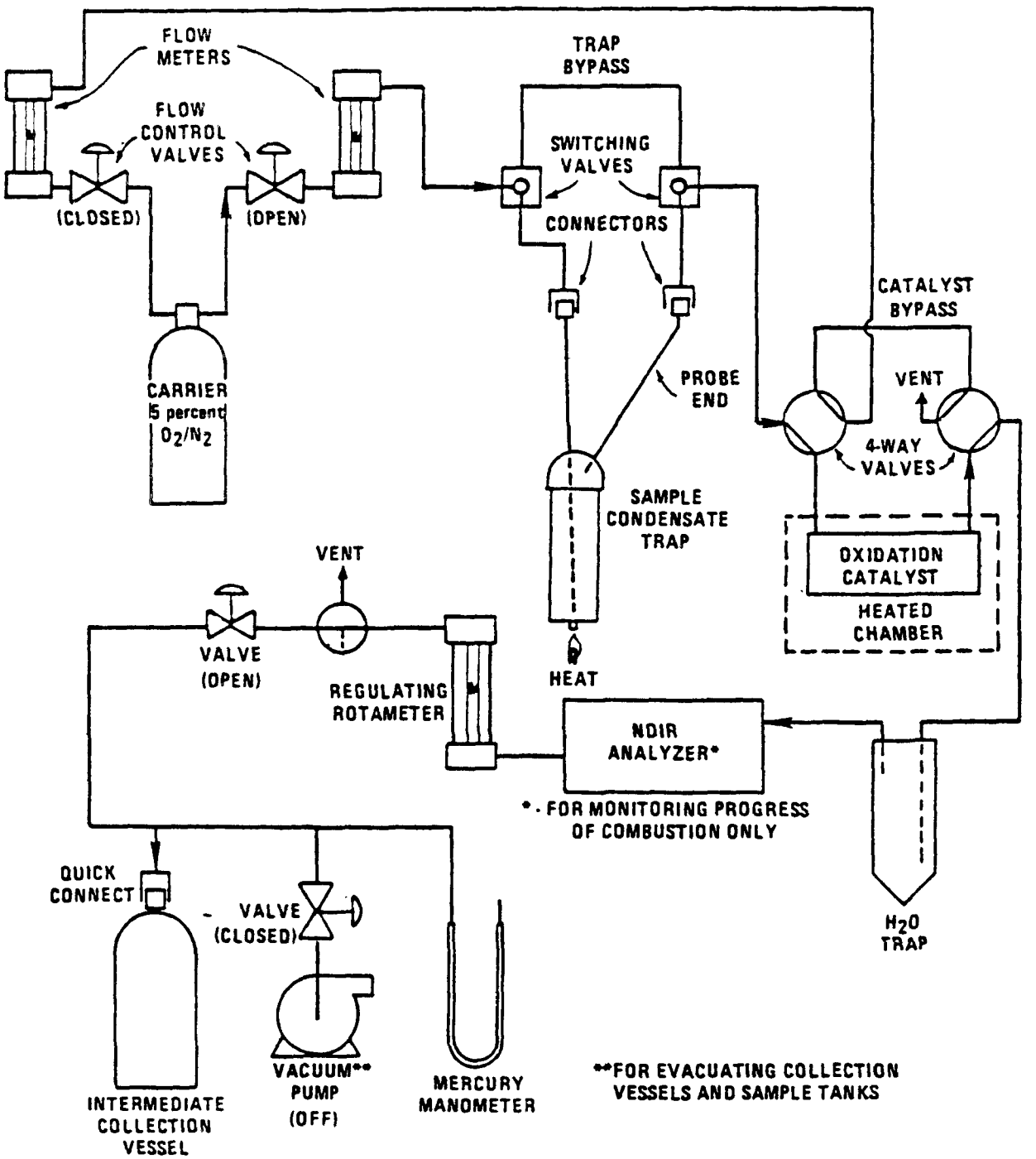


Figure 9. Condensate recovery and conditioning apparatus, collection of trap organics.

4.3.3 Recovery of Condensate Trap Sample. Oxidation and collection of the sample in the condensate trap is now ready to begin. From the step just completed in paragraph 4.3.2 above, the system should be set up so that the carrier flow bypasses the condensate trap, bypasses the oxidation catalyst, and is vented to the atmosphere. Attach an evacuated intermediate collection vessel to the system and then, switch the carrier so that it flows through the oxidation catalyst. Monitor the NDIR and assure that the analyzer indicates a zero output level. Switch the carrier from vent to collect and open the collection tank valve; remove the dry ice from the trap and then switch the carrier flow through the trap. The system should now be set up to operate as indicated in Figure 9.

Begin heating the condensate trap. The trap should be heated to a temperature at which the trap glows a "dull red" (approximately 600° C) and should be maintained at this temperature for at least 5 minutes. During oxidation of the condensate trap sample, monitor the NDIR to determine when all the sample has been removed and oxidized (indicated by return to baseline of NDIR analyzer output). When complete recovery has been indicated, remove the heat from the trap. However, continue the carrier flow until the intermediate collection vessel is pressurized to a gauge pressure of 800 mm Hg (nominal). When the vessel is pressurized, vent the carrier; measure and record the final intermediate collection vessel pressure (P_f) as well as the barometric pressure (P_{bv}), ambient temperature (T_v), and collection vessel volume (V_v).

4.3.4 Analysis of Recovered Condensate Sample. After the preparation steps in paragraph 4.3.1 have been completed, the analyzer is ready for conducting analyses. Assure that the analyzer system is set so that the carrier gas is routed through the reduction catalyst to the FID (flow through the separation column and oxidation catalyst is optional). Attach the intermediate collection vessel to the tank inlet fitting of the TGNMO analyzer. Purge the sample loop with sample and then inject a preliminary sample in order to determine the appropriate FID attenuation. Inject triplicate samples from the intermediate collection vessel and record the values (C_{cm}). When appropriate, check the instrument calibration according to the procedures of paragraph 4.4.1.4.

4.3.5 Analysis of Gas Sample Tank. Assure that the analyzer is set up so that the carrier flow is routed through the separation column as well as both the oxidation and reduction catalysts. During analysis for the nonmethane organics the separation column is operated as follows: First, operate the column at −78° C (dry ice temperature) to elute the CO and CH_4. After the CH_4 peak, operate the column at 0° C to elute the CO_2. When the CO_2 is completely eluted, switch the carrier flow to backflush the column and simultaneously raise the column temperature to 100° C in order to elute all nonmethane organics. (Exact timings for column operation are determined from the calibration standard). Attach the gas sample tank to the tank inlet fitting of the TGNMO analyzer. Purge the sample loop with sample and inject a preliminary sample in order to determine the appropriate FID attenuation for monitoring the backflushed non-methane organics. Inject triplicate samples from the gas sample tank and record the values obtained for the nonmethane organics (C_{tm}). When appropriate, check the instrument calibration according to the procedures of paragraph 4.4.1.4.

4.4 Calibration. Maintain a record of performance of each item.

4.4.1 TGNMO Analyzer.

4.4.1.1 FID Calibration and linearity check. Set up the TGNMO system so that the carrier gas bypasses the oxidation and reduction catalysts. Zero and span the FID by injecting samples of the high value (5–10 percent) calibration gas (paragraph 3.3.1.3) and adjusting the instrument output to the correct level. Then check the instrument linearity by injecting triplicate samples of the low (5–10 ppm) and mid-range (500–1,000 ppm) calibration gases (paragraph 3.3.1.3). The system linearity is acceptable if the results (average for triplicate samples of each gas) are within ±5 percent of the expected values. This calibration and linearity check shall be conducted prior to analyzing each set of samples (i.e., samples from a given source test).

4.4.1.2 Oxidation Catalyst Efficiency Check. This check should be performed on a frequency established by the amount of use of the analyzer and the nature of the organic emissions to which the catalyst is exposed. As a minimum, perform this check prior to putting the analyzer into service.

To confirm that the oxidation catalyst is functioning in a correct manner, the operator must turn off or bypass the reduction catalyst while operating the analyzer in an otherwise normal fashion. Inject triplicate samples of the methane standard gas (paragraph 3.3.1.1) into the system. If oxidation is adequate, the only gas that will then reach the detector will be CO_2, to which the FID has no response. If a response is noted, the oxidation catalyst must be replaced.

4.4.1.3 Reduction Catalyst Efficiency Check. This check should be performed on a frequency established by the amount of use of the analyzer. As a minimum, perform this check prior to putting the analyzer into service. To confirm proper operation of the reduction catalyst, the operator must bypass the oxidation catalyst while operating the analyzer in an otherwise normal manner. After setting the carrier flow to bypass the oxidation catalyst, inject triplicate samples of the carbon dioxide standard gas (Section 3.3.1.2). The catalyst operation is acceptable if the average response of the triplicate CO_2 sample injections is within ±2 percent of the expected value and no one CO_2 sample injection varies by more than ±5 percent from the expected value.

4.4.1.4 System Operation Check. This system check should be conducted at a frequency consistent with the amount of use and the reliability of the particular analyzer. As a minimum, this system check shall be conducted before and after each set of emission samples is analyzed. If this system check is not successfully completed at the conclusion of the analyses, the results shall be invalidated. Operate the TGNMO analyzer in a normal fashion, passing the carrier flow through the separation column and both the oxidation and reduction catalysts. Inject triplicate samples of the two mixed gas standards specified in Section 3.3.1.4. The system operation is acceptable if, for each gas mixture, the average non-methane organic value for the triplicate samples is within ±3 percent of the expected value and no one sample analysis varies by more than ±5 percent from the average value for the triplicate samples.

4.4.2 Condensate Trap Recovery and Conditioning Apparatus Oxidation Catalyst Check. This catalyst check should be conducted at a frequency consistent with the amount of use of the catalyst, as well as, the nature and concentration level of the organics being recovered by the system. As a minimum, perform this check prior to and immediately after conditioning each set of emission sample traps.

Set up the condensate trap recovery system so that the carrier flow bypasses the trap inlet and is vented to the atmosphere at the system outlet. Assure that the tank collection valve is closed and then attach an evacuated intermediate collection vessel to the system. Connect the methane standard gas cylinder (Section 3.3.1.1) to the

system's condensate trap connector (probe end, figure 4). Adjust the system valving so that the standard gas cylinder acts as the carrier gas; switch off the carrier and use the cylinder of standard gas to supply a gas flow rate equal to the carrier flow normally used during trap sample recovery. Now switch from vent to collect in order to begin collecting a sample. Continue collecting a sample in the normal manner until the intermediate vessel is filled to a nominal pressure of 300 mm Hg. Remove the intermediate vessel from the system and vent the carrier flow to the atmosphere. Switch the valving to return the system to its normal carrier gas and normal operating conditions. Set up the TGNMO analyzer to operate with the oxidation and reduction catalysts bypassed. Inject a sample from the intermediate collection vessel into the analyzer. The operation of the condensate trap recovery system oxidation catalyst is acceptable if oxidation of the standard methane gas was 99.5 percent complete, as indicated by the response of the TGNMO analyzer FID.

4.4.3 Gas Sampling Tank. The volume of the gas sampling tanks used must be determined. Prior to putting each tank in service, determine the tank volume by weighting the tanks empty and then filled with water; weight to the nearest 0.5 gm and record the results.

4.4.4 Intermediate Collection Vessel. The volume of the intermediate collection vessels used to collect CO_2 during the analysis of the condensate traps must be determined. Prior to putting each vessel into service, determine the volume by weighting the vessel empty and then filled with water; weigh to the nearest 0.5 gm and record the results.

5. *Calculations.*

Note. All equations are written using absolute pressure; absolute pressures are determined by adding the measured barometric pressure to the measured gauge pressure.

5.1 Sample Volume. For each test run, calculate the gas volume sampled:

$$V_s = 0.386\ V\left(\frac{P_t}{T_t}\right) - \left(\frac{P_{ti}}{T_{ti}}\right)$$

5.2 Noncondensible Organics. For each collection tank, determine the concentration of nonmethane organics (ppm C):

$$C_t = \frac{\frac{P_{tf}}{T_{tf}}}{\frac{P_t}{T_t} - \frac{P_{ti}}{T_{ti}}} \times \frac{1}{r} \times \sum_{j=1}^{r} C_{tm_j}$$

5.3 Condensible Organics. For each condensate trap determine the concentration of organics (ppm C):

$$C_c = 0.386 \frac{V_v \times P_f}{V_s \times T_f} \times \frac{1}{N} \times \sum_{k=1}^{n} C_{cm_k}$$

5.4 Total Gaseous Nonmethane Organics (TGNMO). To determine the TGNMO concentration for each test run, use the following equation:

$C = C_t + C_c$

Where:

C = Total gaseous nonmethane organic (TGNMO) concentration of the effluent, ppm carbon equivalent.

C_c = Calculated condensible organic (condensate trap) concentration of the effluent, ppm carbon equivalent.

C_{cm} = Measured concentration (TGNMO analyzer) for the condensate trap (intermediate collection vessel), ppm methane.

C_t = Calculated noncondensible organic concentration of the effluent, ppm carbon equivalent.

C_{tm} = Measured concentration (TGNMO analyzer) for gas collection tank sample, ppm methane.

P_f = Final pressure of intermediate collection vessel, mm Hg, absolute.

P_{ti} = Gas sample tank pressure prior to sampling, mm Hg, absolute.

P_t = Gas sample tank pressure after sampling, but prior to pressurizing, mm Hg, absolute.

P_{tf} = Final gas sample tank pressure after pressurizing, mm Hg, absolute.

T_f = Final temperature of intermediate collection vessel, °K.

T_{ti} = Gas sample tank temperature prior to sampling, °K.

T_t = Gas sample tank temperature at completion of sampling, °K.

T_{tf} = Gas sample tank temperature after pressurizing, °K.

V = Gas collection tank volume, dscm.

V_v = Intermediate collection tank volume, dscm

V_s = Gas volume sampled, dscm.

r = Total number of analyzer injections of tank sample during analysis (where j = injection number, 1 . . . r).

n = Total number of analyzer injections of condensible intermediate collection vessel during analysis (where k = injection number, 1 . . . n).

Standard Conditions = Dry, 760 mm Hg, 293°K.

6. *Bibliography.*

6.1 Albert E. Salo, Samuel Witz, and Robert D. MacPhee. "Determination of Solvent Vapor Concentrations by Total Combustion Analysis: A comparison of Infrared with Flame Ionization Detectors." Presented at the 68th Annual Meeting of the Air Pollution Control Association, Boston, Ma. Paper No. 75-33.2 June 15-20, 1975.

6.2 Albert E. Salo, William L. Oaks, Robert D. MacPhee. "Measuring the Organic Carbon Content of Source Emissions for Air Pollution Control." Presented at the 67th Annual Meeting of the Air Pollution Control Association, Denver, Colorado, Paper No. 74-190, June 9-13, 1974.

[FR Doc 79-30806 Filed 10-4-79 8:45 am]

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

PHOSPHATE ROCK PLANTS

SUBPART NN

[40 CFR Part 60]

[FRL-1282-2]

Standards of Performance for New Stationary Sources; Phosphate Rock Plants

AGENCY: Environmental Protection Agency.

ACTION: Proposed Rule and Announcement of Public Hearing.

SUMMARY: This action is being proposed to limit emissions of particulate matter from new, modified, and reconstructed phosphate rock plants. Reference Method 5 would be used for determining compliance with these standards. The standards implement the Clean Air Act and result from the Administrator's determination on August 21, 1979 (44 FR 49222) that phosphate rock plant emissions contribute significantly to air pollution. The intended effect is to require new, modified, and reconstructed phosphate rock plants to use the best demonstrated system of emission reduction, considering costs, nonair quality health and environmental impact and energy impacts.

DATES: *Comments.* Deadline for comments is November 26, 1979.

Public hearing. A public hearing will be held on October 25, 1979.

Requests to speak at hearing. Persons wishing to speak at the hearing must contact Shirley Tabler, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5421 by October 18, 1979.

ADDRESSES: *Comments.* Comments should be submitted to the Central Docket Section (A-130), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, D.C. 20460. Attention: Docket No. OAQPS-79-6.

Background Information. The Background Information Document for the proposed standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number: (919) 541-2777. Please refer to "Phosphate Rock Plants, Background Information: Proposed Standards of Performance" (EPA-450/3-79-017).

Docket. A docket (number OAQPS-79-6) containing information used by EPA in development of the proposed standard is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Don Goodwin, Director, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Summary of Proposed Standards

The proposed standards would apply to new, modified, or reconstructed phosphate rock dryers, calciners, grinders, and ground rock handling and storage facilities. The proposed standards would limit emissions of particulate matter to 0.02 kilogram (kg) per megagram (Mg) of rock feed (0.04 lb/ton) from phosphate rock dryers, 0.055 kg/Mg (0.11 lb/ton) from phosphate rock calciners, and 0.006 kg/Mg (0.012 lb/ton) from phosphate rock grinders. An opacity standard of zero percent opacity is proposed for ground rock handling system, dryers, calciners, and grinders.

The use of continuous opacity monitoring systems would be required for each affected facility. However, when scrubbers are used for emission control, continuous opacity monitoring would not be required. Instead, the pressure drop of the scrubber and the liquid supply pressure would be monitored as indicators of the scrubber performance.

Summary of Environmental and Economic Impacts

The proposed standards would impact an estimated 110 teragrams (122 million tons) of annual phosphate rock production by 1995. About one half of that would be due to construction of new phosphate rock processing plants and the remainder due to expansion of industry capacity at existing plants.

The proposed standards would reduce the particulate emissions from new phosphate rock plants by about 99 percent below the levels that would occur with no control and by about 85 to 98 percent below the levels allowed by typical State standards, depending on the type of facility. These emission reductions would reduce nationwide particulate emissions by about 19 gigagrams (21,000 tons) per year in 1985. The maximum 24-hour average ambient air concentration of particulate matter due to emissions from a typical dryer controlled to the level required by the proposed standard would be about 88 $\mu g/m^3$. Similarly, for a typical calciner, imposition of the proposed emission standard would result in a maximum ambient level of 14 $\mu g/m^3$, and for a typical grinder the ambient level could reach a maximum of 1 $\mu g/m^3$.

The annualized costs of operating control equipment that would be needed to attain the proposed standards were estimated using model plants. Because typical Florida phosphate rock plants are larger than Western plants, the control costs per ton of production are lower.

The annualized cost of installing and operating prevailing controls used to meet existing State standards at typical Florida phosphate rock plants is estimated at $0.35 per metric ton. The additional cost of employing control technology to meet the proposed standards at a new Florida plant is estimated at $0.02/metric ton when using baghouses and $0.07/metric ton for scrubbers.

The annualized cost of using prevailing controls to meet existing State standards in a typical new Western plant is $0.87/metric ton. The additional cost of using control technology to meet the proposed standards at new Western plants is estimated at $0.06/metric ton for baghouse control and $0.21/metric ton for scrubbers.

The additional costs of meeting the proposed standards are relatively minor when scrubbers or baghouses are used. Electrostatic precipitators (ESP) could also be used to meet the proposed standards, but their use is not anticipated because of their higher annualized costs of operation. The difference in cost between using the best system of emission reduction to meet the proposed standards level and using prevailing controls to meet the State Implementation Plan (SIP) levels would have negligible impact on the profitability of the plant and the future growth of the phosphate rock industry if the proposed standards were implemented. By the year 1985, compliance with the proposed standards would increase the industry cost of production of phosphate rock by 0.1 percent (baghouse controls) to 0.2 percent (scrubber controls) above the cost to meet existing State Implementation Plan regulations. A more detailed discussion of the economic analysis is discussed in the Background Information Document.

Assuming baghouses are used to meet the proposed standards, the total industry capital cost for the first five years after imposition of the proposed standards would be about $8.5 million greater than the capital costs incurred meeting typical State standards. The total industry annualized cost increase to meet the proposed standards by the fifth year would be about $0.8 million.

The incremental energy required to meet the proposed standards depends on the control utilized. If baghouses are employed, total industry energy consumption in the fifth year after imposition of the proposed standards will increase by about 1.7 percent over the levels projected to occur under State regulations. Total industry consumption in the fifth year will increase by 2.6 percent when scrubbers are employed, and about 0.1 percent should electrostatic precipitators be used. This corresponds to a fifth year total increase in industry energy consumpton of 39 x 10^6 kWh/yr when baghouses are used, 60 x 10^6 kWh/yr when high energy scrubbers are used, and .009 x 10^6 kWh/yr when electrostatic precipitators are used.

Utilization of any of the alternative control technologies (baghouse, scrubber, or ESP) would result in minimal adverse environmental impacts. If high energy scrubbers or wet ESPs are used to achieve the standards, this would result in adverse impacts on solid waste disposal, water pollution, and energy consumption. However, the incremental increase (over the prevailing controls) of solid materials and wastewaters produced during control of emissions from phosphate rock facilities is minor in comparison with (1) the large volumes of process wastewaters and solid wastes, and (2) the total amounts of wastewaters and solid waste already collected by prevailing controls to meet existing State standards. Utilization of baghouse technology is marginally more environmentally acceptable than other control alternatives because no water pollution and less solid waste is produced.

Rationale for the Proposed Standards

Selection of Source for Control

Section 111 of the Act requires establishment of standards of performance for new, modified, or reconstructed stationary sources that cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA has determined that sources which cause ambient suspended particulate matter may cause adverse health and welfare effects. Accordingly, under the authority of Section 109 of the Act, the Administrator has designated particulate matter as a criteria pollutant and has established national ambient air quality standards for this pollutant.

Phosphate rock processing plants have been shown to be a significant source of particulate matter emissions. The Priority List of sources for New Source Performance Standards (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) identified various sources of emissions on a nationwide basis in terms of the potential improvement in emission reduction that could result from their imposition. The sources on this list are ranked based on decreasing order of potential emission reduction. Phosphate rock plants currently rank 16th of 59 sources on the list, and are, therefore, of considerable importance nationwide. In addition, a study performed for EPA in 1975 by the Argonne National Laboratory showed phosphate rock dryers ranked 4th of the nation's highest 18 particulate source categories which require control systems with moderate energy consumption. The same study showed phosphate rock grinders as ranking fifteenth of the nation's 56 largest particulate source categories. Finally, results of dispersion modeling analysis indicate that particulate emission sources at phosphate rock plants contribute significantly to the deterioration of air quality.

Additional factors leading to the selection of the phosphate rock industry for the development of standards of performance include the expected growth rate of the industry and the signficant reductions in particulate matter emissions achievable with application of available emissions control technology. The United States is the largest producer and consumer of phosphate rock in the world. From 1959 to 1973, the production of phosphate rock increased at an annual rate of about six percent and production is expected to increase at an annual rate of about three percent per year through the year 2000. By the year 1985 new and modified phosphate rock plants would cause an increase in nationwide emissions of particulate matter of about 19 gigagrams per pear (21,000 tons/year) above the level expected with implementation of the proposed standards. At most plants, the degree of emissions control (imposed by State Implementation plans) is considerably less than that achievable with application of the best technology for emission control.

Selection of Affected Facility and Pollutants

At phosphate rock installations, the normal sequence of operation is: Mining, beneficiation, conveying of wet rock to and from storage, drying or calcining or nodulizing, conveying and storage of dry rock, grinding, and conveying and storage of ground rock. Mining and beneficiation are a minor source of particulate emissions. Nodulizing, and elemental phosphorous production are not selected as affected facilities as these sources are not expected to exhibit growth potential. Dryers, calciners, grinders and ground rock handling systems account for nearly all of the particulate matter emissions from phosphate rock plants. Accordingly, the proposed standards have been developed for these sources.

Phosphate rock processing plants are sources of emissions of particulates, fluorides, sulfur dioxide (SO_2) and certain radioactive substances. Standards are being proposed only for the control of particulate matter emissions at this time. Based on Tennessee Valley Authority research, and emission measurements of fluorides in calciner exhaust gases, it is unlikely that significant quantities of fluorine will be volatized at temperatures experienced in dryers or calciners. Emission of sulfur oxides generated by oil-firing in dryers and calciners is minimized by reaction with alkaline materials naturally occurring in the phosphate rock ore. Additional studies of the radioactive materials in the emissions are planned and EPA could, if warranted, take additional action under Section 112 of the Clean Air Act at a future date.

Potential particulate emissions from typical uncontrolled phosphate rock facilities would amount to about 2.9 kg/Mg (5.8 lb/ton) of rock feed from the dryer, 7.7 kg/Mg (15.4 lb/ton) of rock feed from the calciner, and about 0.8 kg/Mg (1.6 lb/ton) of rock feed from the grinder. The typical State emission limit for dryers is 0.13 kg/Mg (0.26 lb/ton), and the limit for calciners and grinders is about 0.44 kg/Mg (0.88 lb/ton). Through application of alternative control technology (e.g., the baghouse, or high energy scrubber), the emissions from these facilities could be further reduced to 0.02 kg/Mg (0.04 lb/ton) for dryers, 0.055 kg/Mg (0.11 lb/ton) for calciners, and 0.006 kg/Mg (0.012 lb/ton) for grinders. Control limits for ground rock handling and storage operations are difficult to define owing to wide variations in system equipment and the numerous fugitive emission sources contained in these systems. At most installations, particulate emissions are collected by an evacuation system and vented through a baghouse. Greater assurance that such control system are installed, operated and maintained in accordance with good practice can be achieved by enforcing stringent opacity standards.

Selection of Best System of Emission Reduction Considering Costs

Based on potential environmental, economic and energy impacts, EPA has concluded that either a fabric filitration system or a high energy venturi scrubber system is the best technological system of continuous particulate emissions reduction from each of the affected facilities. The fabric filtration system, high energy scrubber and high efficiency electrostatic precipitator are judged to be equally effective in terms of emissions reduction capability. The proposed standards are, therefore, based on the use of any of the three alternative control methods, although cost considerations would favor the use of the baghouse or high energy scrubber over the ESP.

The economic and environmental adverse impacts associated with the alternative controls would favor the use of the baghouse controls. The eonomic and environmental advantages of the baghouse are most apparent at grinding and material handling/storage facilities, where baghouses are already the prevailing control employed. In contrast to the baghouse, wet collection systems produce water pollution and more solid waste, although the incremental adverse environmental impact produced by these systems is small in comparison with adverse effects presently produced by phosphate rock plant processes, and would not preclude the use of these systems as environmentally acceptable control alternatives.

Selection of Format for Standard

The format of the proposed standard could be either a concentration standard or a mass-per-unit-of-feed standard. A control efficiency format could not be selected because of limited scope in the data base and practical considerations involving the complexity of performance test requirements. An equipment standard was not considered because Section 111 of the Act requires application of emission limits when feasible. The mass-emission-per-unit-feed standard was selected over the concentration standard format because this format: (1) Is related directly to the total quantity of emissions discharged to the atmosphere, (2) is more equitable in that the degree of emissions permitted is related to the amount of product processed, (3) is consistent with the format of existing applicable State standards, (4) does not discourage use of more efficient process systems which reduce exhaust gas volumes, and (5) provides that the standard is not circumvented by dilution or high volume flows in the exhaust system. The mass emissions format is appropriate for the dryers, calciners, and grinder facilities. However, because of wide variations in the designs of ground rock handling systems, and because a substantial portion of the potential emissions are fugitive and difficult to measure, a visible emission standard is the only format appropriate for ground rock handling systems.

Emission Standards for Dryers

Source tests were conducted on dryers at two phosphate rock plants processing pebble rock. The pebble rock is considered to present the most adverse conditions for control of emissions from dryers because it receives relatively little washing and enters the dryer containing a substantial percentage of clay. Hence, any control level limit for dryers processing pebble rock should also be capable of meeting the limit for all other dryers as well.

Particulate emissions from the dryer controlled by a venturi scrubber operating at about 4.4 kilopascals pressure drop (18 inches of water) averaged 0.020 and 0.019 kg/Mg (0.039 and 0.038 lb/ton) for separate EPA tests. Particulate emissions from the dryer controlled by an ESP averaged 0.012 and 0.027 kg/Mg (0.024 and 0.054 lb/ton) for EPA and operator tests, respectively. The test results show that the venturi scrubber was capable of achieving emission levels of 0.02 kg/Mg or better from phosphate rock dryers emitting high levels of particulates. The tests also revealed that the venturi scrubber was achieving a control efficiency of 99.2 percent. This is nearly equivalent to that estimated to be attainable by the best system of emission reduction (99.4 percent by a baghouse) when treating the same emission loading and particle size distribution. Based on analysis using a programmable EPA scrubber model (the model is described in EPA report No. EPA-600/7-78-026), it was estimated that increasing the scrubber energy to a pressure drop of 6.2 kilopascals (25 inches of water) would achieve the degree of control equivalent to the best system of emission reduction, reducing emission levels only marginally (about 20 percent) below that measured. It is concluded, therefore, that an emission limit of 0.02 kg/Mg (0.04 lb/ton) represents the emission level attainable by the best system of emission reduction.

Opacity data were gathered during particulate tests at the two dryers. Approximately fourteen hours of measurements on four separate dates were obtained as specified in EPA Reference Method 9. At one facility where emissions were controlled by a medium-energy venturi scrubber, the observations revealed zero percent opacity throughout the test periods. At the other facility, where emissions were controlled by an ESP, opacity observations ranged from zero percent to 7.7 percent. The difference between the opacity levels observed for the two types of control systems primarily reflected differences in diameters of discharge stacks rather than significant differences in control performance. ESPs typically require larger stacks due to higher volumes of flow required during operation. Setting separate opacity standards for the two control systems was rejected because ESPs are not expected to be used in meeting the proposed standards. Thus the proposed opacity standard is based on the performance of the scrubber-controlled facility and is set at zero percent opacity. Control systems reflecting best emissions control capability (the high energy scrubber or baghouse) which meets the proposed emissions limit should experience no difficulty meeting the proposed opacity standard. Should any affected dryer facility be controlled with an ESP and comply with the particulate limit of 0.02 kg/Mg but not the opacity limits, a separate opacity limit may be established for the facility under 40 CFR 60.11(e). The provisions of 40 CFR 60.11(e) allow owners or operators of sources which exceed the opacity standard while concurrently achieving the performance emissions limit to request establishment of a specific opacity standard for that facility.

Emission Standards for Calciners

Source tests were conducted on calciners at two phosphate rock plants processing western phosphate rock. The western rock is considered to present the most adverse conditions for emissions control from calciners because it receives less cleaning during beneficiation than other ore types. In addition one of the calciners selected for test also processes a mix of both beneficiated and unbeneficiated rock, leading to a still more adverse control problem. Presumably, any control system demonstrating an emissions level for these facilities should also be capable of meeting this level for all other calciners as well.

Particulate emissions from a calciner controlled by a high-energy scrubber operating in the range of 4.9 to 7.4 kilopascals pressure drop (twenty to thirty inches of water) averaged 0.04 and 0.05 kg/Mg (0.08 and 0.10 lb/ton) for two different tests by the operator.

Particulate emissions from a calciner controlled by a venturi scrubber

operating at 3.0 kilopascals pressure drop (12 inches of water) averaged 0.07 kg/Mg (0.14 lb/ton) for EPA tests and 0.12 and 0.068 kg/Mg (0.24 amd 0.136 lb/ton) for different operator tests. The emission level which would have been attained had best technology been used by this facility is estimated by adjusting the test results to reflect the venturi scrubber performance at 6.8 kilopascals (27 inches water) pressure drop using the EPA programmable scrubber model Section 8.5 of the Background Information Document for Phosphate Rock Plants summarizes the expected emission levels when the scrubber energy is increased from medium to high level. The adjusted level of control is equivalent to that which would be expected if baghouses were employed to control calciner emissions, or 0.055 kg/Mg (0.11 lb/ton). Accordingly, this control level is proposed as the emission limit for calciners.

Opacity data were obtained during the performance testing of the two calciners. Zero percent opacity was recorded at both facilities throughout the 13.75 hours of observations. Based on these test data, plus the fact that better control technology must be installed to comply with the performance limits, it is proposed that the opacity limit for calciner facilities be set at zero percent opacity.

Emission Standards for Grinders

Source tests were conducted on four separate grinders representing a wide variation of exhaust air rates, grinder designs, capacities, and product feeds Emissions from each of the facilities are controlled with baghouses. Emissions averaged 0.0044, 0.002, 0.0005, and 0.0005 kg/Mg for EPA tests and 0.0022 kg/Mg for operator tests. The emission tests demonstrate that an emission level of 0.005 kg/Mg (0.01 lb/ton) can be achieved by fabric filters for a variety of grinder applications. Installation of baghouse controls for grinders is motivated by the recovery value of the product collected as much as by existing emission standards. Hence, it is expected that baghouses will remain the predominant means of compliances with emission standards for grinder facilities

Nearly 17 hours of opacity observations were gathered during particulate tests at two of the grinder facilities. The average opacity level recorded throughout the measurement periods was zero percent. The use of baghouses as control devices on these two facilities represents demonstrated best technology, therefore, the Administrator believes that the opacity standard for phosphate rock grinding processes should be zero percent opacity.

Emission Standards for Ground Rock Handling and Storage Systems

Particulate emissions from handling and storage of ground rock are very difficult to characterize due to the fact that these systems vary greatly from plant to plant. A substantial portion of the potential emissions from handling and storage operations is fugitive emissions. Normal industrial practice is to control dust from the various sources by utilizing enclosures and air evacuation or pressure systems ducted to baghouses. Baghouses provide recovery of the rock dust which is subsequently returned to the rock inventory. Emissions from the enclosures have zero percent opacity when the process equipment is properly maintained. Consequently, emissions from the ground rock transfer system are manifested and monitored at the overall collection device (e.g., the baghouse). Because of wide variations in handling and storage facilities, an opacity standard is the only standard appropriate for these facilities.

Source tests were conducted on three pneumatic systems employed in the transfer of ground phosphate rock. The exhaust from the baghouses of each of the transfer systems was witnessed to determine the opacity of emissions during normal transfer operations for two hours at one system, and one hour at the others. The opacity level of the baghouse emissions was observed to be zero percent throughout the test period. Based on these results, an opacity limit of zero percent opacity is proposed for ground phosphate rock handling systems

Testing, Monitoring, and Recordkeeping

Performance tests to determine compliance with the proposed standards would be required. Reference Method 5 (40 CFR Part 60, Appendix A) would be used to measure the amount of particulate emissions.

The proposed standards would require continuous monitoring of the opacity of emissions discharged from phosphate rock dryers, calciners, grinders and ground rock handling systems. When a scrubber is used to control the emissions, entrained water droplets prevent the accurate measurement of opacity; therefore, in this case the proposed standard would require monitoring the pressure drop across the scrubber and the scrubbing fluid supply pressure to the scrubber rather than opacity. If other controls are employed which would also preclude the use of a continuous monitoring system for measuring opacity as specified by the standard, the operator may request establishment of alternative monitoring requirements under the provisions of 40 CFR 60.13(i).

Excess emissions for affected facilities using opacity monitoring equipment are defined as all six-minute periods in which the average opacity of the stack plume exceeds zero percent. Reporting of any excess emissions is required under 40 CFR 60 on a quarterly basis. For those facilities which use a wet scrubber as the particulate control device, the owner or operator is instead required to submit reports each calendar quarter for all measurements of scrubber pressure drops and liquid supply pressures less than 90 percent of the average levels maintained during the most recent performance test in which compliance with the proposed standards was demonstrated

Public Hearing

A public hearing will be held to discuss these proposed standards in accordance with Section 307(d)(5) of the Clean Air Act. Persons wishing to make oral presentations should contact EPA at the address given in the ADDRESSES Section of this preamble Oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement with EPA before, during, or within 30 days after the hearing

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at the address of the Docket (see ADDRESSES Section)

Docket

The docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The principal purposes of the docket are (1) to allow interested persons to identify and locate documents so that they can intelligently and effectively participate in the rulemaking process, and (2) to serve as the record for judicial review

Miscellaneous

As prescribed by Section 111 of the Act, this proposal of standards was preceded by the Administrator's determination that emissions from phosphate rock plants contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare. In accordance with Section 117 of the Act, publication of this proposal was preceded by consultation with appropriate advisory committees, independent experts, and Federal

departments and agencies. The Administrator will welcome comments on all aspects of the proposed regulation.

Under EPA's sunset policy for reporting requirements in regulations, the reporting requirements in this regulation will automatically expire 5 years from the date of promulgation unless EPA takes affirmative action to extend them. To accomplish this, a provision automatically terminating the reporting requirements at that time will be included in the text of the final regulations.

It should be noted that standards of performance for new sources established under Section 111 of the Clean Air Act reflect the degree of emission limitation achievable through application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

Although there may be emission control technology available that can reduce emissions below those levels required to comply with the standards of performance, this technology might not be selected as the basis of standards of performance because of costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act requires (or has the potential for requiring) the imposition of a more stringent emission standard in several situations. For example, applicable costs do not play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources locating in nonattainment areas; i.e., those areas where statutorily-mandated health and welfare standards are being violated. In this respect, Section 173 of the Act requires that new or modified sources constructed in an area which violates the National Ambient Air Quality Standards (NAAQS) must reduce emissions to the level which reflects the "lowest achievable emission rate" (LAER), as defined in Section 171(3), for such category of source. The statute defines LAER as that rate of emissions based on the following, whichever is more stringent:

(A) The most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable; or,

(B) The most stringent emission limitation which is achieved in practice by such class or category of source.

In no event can the emission rate exceed any applicable new source performance standard (Section 171(3)).

A similar situation may arise under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require that certain sources (referred to in Section 169(1)) employ "best available control technology" (as defined in Section 169(3)) for all pollutants regulated under the Act. Best available control technology (BACT) must be determined on a case-by-case basis, taking energy, environmental and economic impacts and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to Section 111 (or 112) of the Act.

In all events, State Implementation Plans approved or promulgated under Section 110 of the Act must provide for the attainment and maintenance of National Ambient Air Quality Standards (NAAQS) designed to protect public health and welfare. For this purpose, SIPs must in some cases require greater emission reductions than those required by standards of performance for new sources.

Finally, States are free under Section 116 of the Act to establish even more stringent emission limits than those established under Section 111 or those necessary to attain or maintain the NAAQS under Section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under Section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

EPA will review this regulation 4 years from the date of promulgation. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, and improvements in emission control technology.

Executive Order 12044, dated March 24, 1978, whose objective is to improve government regulations, requires executive branch agencies to prepare regulatory analyses for regulations that may have major economic consequences. The screening criteria used by EPA to determine if a proposal requires a regulatory analysis under Executive Order 12044 are: (1) Additional national annualized compliance costs, including capital charges, which total $100 million within any calendar year by the attainment date, if applicable, or within five years, (2) a major increase in prices or production costs.

The impacts associated with the proposal of performance standards for phosphate rock plants do not exceed the EPA screening criteria. Therefore, promulgation of the proposed standard does not constitute a major action requiring preparation of a regulatory analysis under Executive Order 12044. However, an economic impact assessment of alternative control technologies capable of meeting the proposed NSPS has been prepared as required under Section 317 of the Clean Air Act and is included in the Background Information Document for Phosphate Rock Plants. EPA considered all the information in the economic impact assessment in determining the cost of the proposed standard.

Dated: September 14, 1979

Douglas M. Costle,

Administrator.

It is proposed to amend Part 60 of Chapter I of Title 40 of the Code of Federal Regulations as follows:

1. By adding Subpart NN to the Table of Sections as follows:

Subpart NN—Standards of Performance for Phosphate Rock Plants

Sec.

60.400 Applicability and designation of affected facility
60.401 Definitions.
60.402 Standard for particulate matter.
60.403 Monitoring of emissions and operations.
60.404 Test methods and procedures.

Authority. Sec. 111 and 301(a), Clean Air Act, as amended, (42 U.S.C. 7411, 7601(a)), and additional authority as noted below:

2. By adding subpart NN as follows:

Subpart NN—Standards of Performance for Phosphate Rock Plants

§ 60.400 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities used in phosphate rock plants: dryers, calciners, grinders, and ground rock handling and storage facilities.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after September 21, 1979, is subject to the requirements of this part.

§ 60.401 Definitions.

(a) "Phosphate rock plant" means any plant which produces or prepares phosphate rock product by any or all of the following processes: mining, beneficiation, crushing, screening, cleaning, drying, calcining, and grinding.

(b) "Phosphate rock feed" means the ore which is fed to phosphate rock facilities, including, but not limited to the following minerals: Fluorapatite, hydroxylapatite, chlorapatite and carbonate-apatite.

(c) "Dryer" means a unit in which the moisture content of phosphate rock is reduced by contact with a heated gas stream.

(d) "Calciner" means a unit in which the moisture and organic matter of phosphate rock is reduced within a combustion chamber.

(e) "Grinder" means a unit which is used to reduce the size of dry phosphate rock.

(f) "Ground phosphate rock handling and storage system" means a system which is used for the conveyance and storage of ground phosphate rock.

§ 60.402 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere:

(1) From any phosphate rock dryer any gases which:

(i) Contain particulate matter in excess of 0.020 kilogram per megagram of phosphate rock feed (0.04 lb/ton), or

(ii) Exhibit greater than 0 percent opacity.

(2) From any phosphate rock calciner any gases which:

(i) Contain particulate matter in excess of 0.055 kilogram per megagram of phosphate rock feed (0.11 lb/ton), or

(ii) Exhibit greater than 0 percent opacity.

(3) From any phosphate rock grinder any gases which:

(i) Contain particulate matter in excess of 0.006 kilogram per megagram of phosphate rock feed (0.012 lb/ton), or

(ii) Exhibit greater than 0 percent opacity.

(4) From any phosphate rock handling and storage system any gases which exhibit greater than 0 percent opacity.

§ 60.403 Monitoring of emissions and operations

(a) Any owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate a continuous monitoring system, except as provided in paragraph (b) of this section, to monitor and record the opacity of the gases discharged into the atmosphere from any phosphate rock dryer, calciner, grinder or ground rock handling system. The span of this system shall be set at 40 percent opacity.

(b) The owner or operator of any affected phosphate rock facility using a wet scrubbing emission control device shall not be subject to the requirements in paragraph (a) of this section, but shall install, calibrate, maintain, and operate the following continuous monitoring devices:

(1) A monitoring device for the continuous measurement of the pressure loss of the gas stream through the scrubber. The monitoring device must be certified by the manufacturer to be accurate within ±250 pascals (±1 inch water) gauge pressure.

(2) A monitoring device for the continuous measurement of the scrubbing liquid supply pressure to the control device. The monitoring device must be accurate within ±5 percent of design scrubbing liquid supply pressure.

(c) For the purpose of conducting a performance test under § 60.8, the owner or operator of any phosphate rock plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a device for measuring the phosphate rock feed to any affected dryer, calciner, grinder, or ground rock handling system. The measuring device used must be accurate to within ±5 percent of the mass rate over its operating range.

(d) For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are defined as all six-minute periods during which the average opacity of the plume from any phosphate rock dryer, calciner, grinder or ground rock handling system subject to paragraph (a) of this section exceeds 0 percent.

(e) Any owner or operator subject to requirements under paragraph (b) of this section shall report for each calendar quarter all measurement results that are less than 90 percent of the average levels maintained during the most recent performance test conducted under § 60.8 in which the affected facility demonstrated compliance with the standard under § 60.402.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))

§ 60.404 Test methods and procedures

(a) Reference methods in Appendix A of this part, except as provided under § 60.8(b) shall be used to determine compliance with § 60.402 as follows:

(1) Method 5 for the measurement of particulate matter and associated moisture content,

(2) Method 1 for sample and velocity traverses,

(3) Method 2 for velocity and volumetric flow rates,

(4) Method 3 for gas analysis, and

(5) Method 9 for the measurement of the opacity of emissions.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the minimum sampled volume of 0.84 dscm (30 dscf) except that shorter sampling times and smaller sample volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) For each run, average phosphate rock feed rate in megagrams per hour shall be determined using a device meeting the requirements of § 60.403(c).

(d) For each run, emissions expressed in kilograms per megagram of phosphate rock feed shall be determined using the following equation:

$$E = \frac{(C_s Q_s) 10^{-6}}{M}$$

Where:

E = Emissions of particulates in kilograms per megagrams of phosphate rock feed.

C_s = Concentration of particulates in mg/dscm as measured by Method 5.

Q_s = Volumetric flow rate in dscm/hr as determined by Method 2.

10^{-6} = Conversion factor for milligrams to kilograms.

M = Average phosphate rock feed rate in megagrams per hour.

(Sec. 114, Clean Air Act, as amended, (42 U.S.C. 7414))

[FR Doc. 79-29399 Filed 9-20-79 8:45 am]

40 CFR Part 60

[FRL 1349-8]

Standards of Performance for New Stationary Sources; Phosphate Rock Plants; Extension of Comment Period

AGENCY: Environmental Protection Agency (EPA).

ACTION: Extension of Comment Period.

SUMMARY: The deadline for submittal of comments on the proposed standards of performance for phosphate rock plants, which were proposed on September 21, 1979 (44 FR 54970), is being extended from November 26, 1979 to December 26, 1979.

DATES: Comments must be received on or before December 26, 1979.

ADDRESSES: Comments should be submitted to Mr. David R. Patrick, Chief, Standards Development Branch (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

FOR FURTHER INFORMATION CONTACT: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5271.

SUPPLEMENTARY INFORMATION: On September 21, 1979 (44 FR 54970), the Environmental Protection Agency proposed standards of performance for the control of particulate emissions from phosphate rock plants. The notice of proposal requested public comments on the standards by November 26, 1979. Due to a delay in the shipping of the Support Document, sufficient copies of the document have not been available to all interested parties in time to allow their meaningful review and comment by November 26, 1979. EPA has received a request from the industry to extend the comment period by 30 days through December 26, 1979. An extension of this length is justified since the shipping delay has resulted in approximately a three-week delay in processing requests for the document.

Dated: October 26, 1979.

David G. Hawkins,

Assistant Administrator for Air, Noise, and Radiation.

[FR Doc. 79-33855 Filed 10-31-79, 8:45 am]

40 CFR Part 60

[FRL 1391-6]

Standards of Performance for New Stationary Sources; Phosphate Rock Plants

AGENCY: Environmental Protection Agency (EPA).

ACTION: Extension of Comment Period.

SUMMARY: The deadline for submittal of comments on the proposed standards of performance for phosphate rock plants, which were proposed on September 21, 1979 (44 FR 54970), is being extended from December 26, 1979, to February 15, 1980. The extension is given because there was about a six week delay in distributing the document for review

DATES: *Comments.* Comments must be received on or before February 15, 1980.

ADDRESSES: *Comments.* Comments should be submitted to Mr. David R. Patrick Chief, Standards Development Branch (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Trinagle Park, North Carolina 27711.

FOR FURTHER INFORMATION CONTACT: Mr. Don R. Goodwin, Director, Emission Stnadards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5271.

SUPPLEMENTARY INFORMATION: On September 21, 1979 (44 FR 54970), the Environmental Protectioin Agency proposed standards of performance for the control of particulate emissions from phosphate rock plants. The notice of proposal requested public comments on the standards by December 26, 1979. Due to a delay in the shipping of the Support Document, sufficient copies of the document have not been available to all interested parties in time to allow their meaningful review and comment by December 26, 1979. EPA has received a request from the industry to extend the comment period by 45 days through February 15, 1980. An extension of this length is justified since the shipping delay has resulted in approximately a six week delay in processing requests for the document.

Dated: January 8, 1980.

David G. Hawkins,

Assistant Administrator for Air, Noise, and Radiation

[FR Doc. 80-1531 Filed 1-16-80, 8:45 am]

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

AMMONIUM SULFATE MANUFACTURE

SUBPART PP

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1353-3]

Standards of Performance for New Stationary Sources; Ammonium Sulfate Manufacture

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed Rule and Notice of Public Hearing.

SUMMARY: The proposed standards would limit atmospheric emissions of particulate matter from new, modified, and reconstructed ammonium sulfate manufacturing dryers. The standards implement section 111 of the Clean Air Act and are based on the Administrator's determination that ammonium sulfate manufacturing plants contribute significantly to air pollution. The intended effect is to require new, modified, and reconstructed ammonium sulfate manufacturing plants to use the best demonstrated system of continuous emission reduction, considering costs, nonair quality health and environmental impact, and energy impacts.

A public hearing will be held to provide interested persons an opportunity for oral presentation of data, views, or arguments concerning the proposed standards.

DATES: *Comments.* Comments must be received on or before April 5, 1980.

Public Hearings. The public hearing will be held on March 6, 1980 (about 30 days after proposal) beginning at 9 a.m.

Request to Speak at Hearing. Persons wishing to present oral testimony at the hearing should contact EPA by February 29, 1980 (one week before hearing).

ADDRESSES: *Comments.* Comments should be submitted (in duplicate if possible) to Central Docket Section (A-130), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, D.C. 20460, Attention: Docket No. A-79-31.

Public Hearing. The public hearing will be held at The Environmental Research Center Auditorium Rm B-102, Research Triangle Park, N.C. Persons wishing to present oral testimony should notify Shirley Tabler, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5421.

Background Information Document. The background information document for the proposed standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Ammonium Sulfate Manufacture—Background Information for Proposed Emission Standards," EPA-450/3-79-034.

Docket. A docket, number A-79-31, containing information used by EPA in development of the proposed standards, is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section (A-130), Room 2903B, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Proposed Standards

The proposed standards would limit atmospheric particulate matter emissions from new, modified, and reconstructed ammonium sulfate dryers at caprolactam by-product ammonium sulfate plants, synthetic ammonium sulfate plants, and coke oven by-product ammonium sulfate plants.

Specifically, the proposed standards would limit exhaust emissions from ammonium sulfate dryers to 0.15 kilogram of particulate matter per megagram of ammonium sulfate production (0.30 lb/ton). An opacity emission standard is also proposed and would limit emissions from the affected facility to no more than 15 percent.

The proposed standards would require continuous monitoring of the pressure drop across the control system for any affected facility to help ensure proper operation and maintenance of the system. Flow monitoring devices necessary to determine the mass flow of ammonium sulfate feed material to the process would also be required.

Summary of Environmental, Energy, and Economic Impacts

The proposed standards would reduce projected 1985 particulate emissions from new, modified, and reconstructed ammonium sulfate dryers from about 670 megagrams (737 tons) per year, the level of emissions under a typical State Implementation Plan, to about 131 megagrams (144 tons) per year. Compliance with the proposed standards would amount to an 80 percent reduction of particulate emissions under a State Implementation Plan and would bring the overall collection efficiency to near 99.9 percent of the uncontrolled emissions. This reduction in emission would result in reduction of ambient air concentrations of particulate matter in the vicinity of new, modified, and reconstructed ammonium sulfate plants. The proposed standards are based on the use of venturi scrubbing or fabric filtration to control particulate matter. No water discharge would be generated by the control equipment required and all captured particulate matter would be reclaimed; therefore, the proposed standards would have no adverse impact on water quality or solid waste.

The proposed standards would not significantly increase energy consumption at ammonium sulfate plants and would have a minimal impact on national energy consumption. The incremental energy needed to operate control equipment to meet the standards would range from 0.10 percent of the total energy required to run a synthetic or coke oven by-product ammonium sulfate plant to 0.65 percent of the total energy required to operate a caprolactam by-product ammonium sulfate plant.

Economic analysis indicates that the impact of the proposed standards is reasonable. Cumulative capital costs of complying with the proposed standards for the ammonium sulfate industry as a whole would be about $1.0 million by 1985. Annualized cost to the industry in the fifth year of the proposed standards would be about $0.5 million. The industry-wide price increase necessary to offset the cost of compliance would amount to less than 0.01 percent of the wholesale price of ammonium sulfate. Costs of emission control required by the proposed standards are not expected to prevent or hinder expansion or continued production in the ammonium sulfate industry.

Rationale

Selection of Source for Control

The Priority List (40 CFR 60.16, 44 FR 49222, August 21, 1979) identifies various sources of emissions on a nationwide basis in terms of quantities of emission from source categories, the mobility and competitive nature of each source category, and the extent to which each pollutant endangers health and welfare. The Priority List reflects the Administrator's determination that emissions from the listed source categories contribute significantly to air pollution and is intended to identify major source categories for which standards of performance are to be promulgated. The ammonium sulfate manufacturing industry is listed among

those source categories for which new source performance standards (NSPS) must be promulgated.

Ammonium sulfate has been an important nitrogen fertilizer for many years. Its early rise to importance as a fertilizer resulted from its availability as a by-product from such basic industries as steel manufacturing and petroleum refining. By-product generation has continued to dominate the industry. By-product ammonium sulfate from the caprolactam segment of the synthetic fibers industry is now the single largest source, accounting for more than 50 percent of ammonium sulfate production.

Production of ammonium sulfate as a by-product also ensures that it will continue as an important source of nitrogen fertilizer in the United States. This is illustrated by the fact that, in response to an increase in demand, caprolactam production is expected to increase at compounded annual growth rates of up to 7 percent through the year 1985; and for every megagram of caprolactam produced, 2.5 to 4.5 megagrams of ammonium sulfate are produced as a by-product.

Over 90 percent of ammonium sulfate is generated from three types of plants: Synthetic, caprolactam by-product, and coke oven by-product. Investigation has shown that the impact of regulation and potential for emission reduction is significant only within these three industry sectors. Synthetic ammomium sulfate is produced by the direct combination of ammonia and sufuric acid. Caprolactam ammomium sulfate is produced as a by-product from streams generated during caprolactam manufacture. Ammonia recovered from coke oven off-gas is reacted with sulfuric acid to produce coke oven ammonium sulfate. These three major segments of the ammonium sulfate industry would be regulated by the proposed new source performance standards.

Selection of Pollutant

Study of the ammonium sulfate industry has shown that ammonium sulfate emissions are the principal pollutant emitted to the atmosphere from ammonium sulfate plants. At operating temperatures, the ammonium sulfate emissions occur as solid particulate matter, a "criteria" pollutant for which national ambient air quality standards have been promulgated.

Currently, a variety of wet collection systems are employed to control ammonium sulfate particulate emissions to levels of compliance with State and local air pollution regulations (typically a reduction of 97 to 98 percent). Existing State regulations range from a low of 0.71 kilogram of particulate per megagram of ammonium sulfate production to a high of 1.3 kilograms per megagram. By the year 1985, new, modified, and reconstructed ammonium sulfate manufacturing dryers would cause annual nationwide particulate emissions to increase by about 670 Mg/year (737 tons/year), with emissions controlled to the level of a typical State Implementation Plan (SIP) regulation. (Estimate based on growth rate demonstrated over past decade.)

Volatile organic compounds (VOC) are also emitted from process dryers at caprolactam by-product ammonium sulfate plants. Test data indicate that the caprolactam VOC mass emissions are largely in the vapor phase and at least two orders of magnitude lower than ammonium sulfate particulate emissions (110 kg/Mg for particulate matter versus 0.78 kg/Mg for the VOC emissions). In addition, wet collectors currently in use as particulate control systems have demonstrated an 88 percent removal efficiency of uncontrolled caprolactam VOC emissions. At this control level, new, modified, and reconstructed caprolactam ammonium sulfate plants would add only about 76 megagrams per year to nationwide VOC emissions by 1985. Therefore, the only pollutant recommended for control by the proposed standards is particulate matter.

Selection of the Affected Facility

Ammonium sulfate crystals are formed by continuously circulating a mother liquor through a crystallizer. When optimum crystal size is achieved, precipitated crystals are separated from the mother liquor (dewatered) usually by centrifuges. Following dewatering, the crystals are dried and screened to product specifications.

Nearly all of the particulate matter emitted to the atmosphere from ammonium sulfate manufacturing plants is in the gaseous exhaust streams from the process dryers. Other plant processes, such as crystallization, dewatering, screening, and materials handling, are not significant emission sources.

Ammonium sulfate dryers can be either of the fluidized bed or the rotary drum type. All fluidized bed units found in the industry are heated continuously with steam-heated air. The rotary units are either direct-fired or steam heated. Air flow rates for the ammonium sulfate dryers at caprolactam plants range from 560 scm/Mg of product to 3,200 scm/Mg of product. The lower value represents direct-fired rotary drum units and the higher value represents fluidized bed drying units using steam-heated air. At synthetic plants, air flow rates range from 360 scm/Mg to 770 scm/Mg of product. All drying units at synthetic plants are of the rotary drum type.

One consequence of the wide range of gas flow rates for the differing drying systems is that particulate emission rates, which are directly related to the gas-to-product ratio, also vary considerably for each drying unit involved. (Gas-to-product ratio is defined as the volume of dryer exhaust gas per unit of production, e.g., dry standard cubic meters per megagram of ammonium sulfate produced.) Emission tests using EPA Method 5 show an uncontrolled ammonium sulfate emission range of 0.44 kg/Mg to 76.7 kg/Mg for rotary dryers. The one fluidized bed dryer tested showed an uncontrolled emission rate of 110 kg/Mg of ammonium sulfate production.

Since the process dryer is the only significant source of ammonium sulfate particulate emissions, the ammonium sulfate manufacturing industry can be effectively controlled by specifying emission limitations for the process dryer. Therefore, the ammonium sulfate dryer has been selected as the affected facility for which particulate matter regulations are proposed.

Selection of the Format of the Recommended Standards

A number of regulatory formats are available for standards limiting the emission of particulate matter to the atmosphere. Among the formats judged as inappropriate for application in the ammonium sulfate industry were a mass per unit time performance standards and such non-performance standards as design, equipment, work practice, and operational specifications. A standard based on mass per unit time (e.g., kg/hr) would require that a relationship be constructed showing how the allowable mass rate of emissions would vary with both production and time. Such a relationship could not be determined without extensive source tests performed at great expense.

Section 111(h) of the Clean Air Act establishes a presumption against design, equipment, work practice, and operational standards. For example, a standard based on a specific type of drying equipment without add-on controls or a standard limiting the dryer air flow rate cannot be promulgated unless a standard of performance is not feasible. Performance standards for control of ammonium sulfate dryer particulate emissions have been determined as practical and feasible; therefore, design, equipment, work

practice, or operational standards were not considered as regulatory options.

Two additional formats for the proposed standards were considered: mass standards, which limit emissions per unit of feed to the ammonium sulfate dryer or per unit of ammonium sulfate processed by the dryer; and concentration standards, which limit emissions per unit volume of exhaust gases discharged to the atmosphere.

Mass standards, expressed as allowable emissions per unit of production, are related directly to the quantity of particulate matter discharged to the atmosphere. They regulate emissions based on units of input or output, thereby denying any dilution advantage. Mass standards also allow for variation in process techniques such as decreasing the air flow rate through the dryer. A primary disadvantage of mass standards, as compared to concentration standards, is that their enforcement may be more time consuming and therefore more costly. The more numerous measurements and calculations required also increase the opportunities for error. Determining mass emissions requires the development of a material balance on process data concerning the operation of the plant, whether it be input flow rates or production flow rates. The need for such a material balance is particularly relevant in the case of ammonium sulfate plants. The determination of throughput in the ammonium sulfate dryer is seldom direct. None of the plants investigated during development of the proposed standards made direct measurements of the dryer input or output. Process weights were determined indirectly through monitoring of input stream feed rates.

In general, enforcement of concentration standards requires a minimum of data and information, thereby decreasing the costs of enforcement and reducing the chances of error. However, in the ammonium sulfate industry, enforcement of concentration standards may be complicated by use of two-stage fluidized bed dryers which add ambient air streams at the discharge end of the dryer. There is a potential for circumventing concentration standards by diluting the exhaust gases discharged to the atmosphere with excess air, thus lowering the concentration of pollutants emitted but not the total mass emitted. For combustion operations, this problem can usually be overcome by correcting the concentration measured in the gas stream to a reference condition such as a specified oxygen or carbon dioxide percentage in the gas stream. However, in the ammonium sulfate industry the drying process frequently does not involve direct combustion operations. The drying air may be heated by an outside source; therefore, it is not always possible to "correct" the amount of exhaust air to account for dilution.

Since design dryer gas flow rates vary from process to process, concentration standards applied to the ammonium sulfate industry would penalize those plant operators who chose to use a low air flow rate for the ammonium sulfate dryer. A decrease in the amount of dryer air decreases the volume of gases released but not necessarily the quantity of particulate matter emitted. As a result, the concentration of particulate matter in the exhaust gas stream would increase even though the total mass emitted might remain nearly the same.

Because mass standards directly limit the amount of particulate matter emitted into the atmosphere per megagram of ammonium sulfate production, the same emission limit can be applied to all dryer types and sizes, production rates, and air flow rates. The flexibility of mass standards to accommodate process variations, such as the wide gange of gas-to-product ratios found in the industry, allows all segments of the ammonium sulfate industry to be regulated with a single mass emission standard. These advantages outweigh the drawbacks associated with the determination of process weight. Consequently, mass standards were judged more suitable for regulation of particulate emissions from ammonium sulfate dryers and were selected as the format for expressing the standards of performance for ammonium sulfate manufacturing plants.

The mass limit proposed will apply to the exhaust gas streams as they discharge from control equipment. The proposed standards express allowable particulate emissions in kilograms per megagram (kg/Mg) of ammonium sulfate production.

Selection of the Best System of Emission Reduction and the Numerical Emission Limits

Section 111 of the Clean Air Act requires that standards of performance reflect the degree of emission control achievable through application of the best demonstrated technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact, and energy requirements) has been adequately demonstrated. The proposed standards were developed based on information derived from (1) available technical literature on the ammonium sulfate manufacturing industry and applicable emission control technology, (2) technical studies performed for EPA by independent research organizations, (3) information obtained from the industry during visits to ammonium sulfate plants and meetings with various representatives of the industry, (4) comments and suggestions solicited from experts, and (5) results of emission measurements conducted by EPA.

Control Technology

Both venturi scrubbing and fabric filtration represent the most efficient add-on control techniques available to abate particulate emissions. In application to particulate collection from ammonium sulfate dryers, both have the potential to reduce ammonium sulfate emissions from process dryers to less than 0.15 kilogram per megagram of ammonium sulfate production, although energy requirements and costs may differ considerably.

Venturi scrubbers are most suitable for application to ammonium sulfate dryers. In caprolactam by-product ammonium sulfate plants, ammonium sulfate feed streams are used as a scrubbing liquor and in synthetic ammonium sulfate plants the condensate from the reactor/crystallizer is used as the scrubbing liquor. This allows the collected particulate to be easily recycled to the system without the addition of excess water. Because medium-energy (25 to 33 centimeters water guage (W.G.) pressure drop) venturi scrubbing with high liquid-to-gas ratios achieves a high collection efficiency and because venturi scrubbing is compatible with and complimentary to the processes involved, it is considered the most attractive add-on control system.

The fabric filter baghouse should also be able to achieve the level of control required by the standards based on similar applications in other industries. Normal operation of a baghouse for ammonium sulfate particulate collection, i.e., at temperatures above the dewpoint of the exhaust gas, should be feasible. However, in asseessing fabric filters as an emission control option, the following factors must be considered. For high gas flow rates, capital and operating costs as well as energy requirements are higher for fabric filters than for medium energy scrubbers of the same construction material. For caprolactam by-product plants using steam-heated fluidized bed dryers, the ratio of gas flow to product rate is at least an order of magnitude higher than that of the direct-fired rotary drum dryer operating with fabric filters. As the size of a

baghouse becomes larger, capital and annual operating costs increase. For example, maintaining the temperature of the exhaust gas and baghouse surfaces above the dewpoint may require more energy than would ordinarily be required to operate the dryer.

With caprolactam by-product ammonium sulfate plants apparently providing most of the anticipated growth in the ammonium sulfate industry, consideration should also be given to caprolactam VOC mass emissions from ammonium sulfate dryers. Available test data indicate that most of the caprolactam emissions associated with the ammonium sulfate dryer are in the vapor state. This suggests that the caprolactam emissions would pass through a fabric filter collection system. On the other hand, a venturi scrubber has demonstrated removal efficiency of 88 percent of the caprolactam from ammonium sulfate dryers. Thus, use of venturi scrubbers would, at a minimum, maintain existing VOC control levels now achieved by in-use wet collection systems.

Emission Tests

Based on a survey of the ammonium sulfate production industry, four plants were selected for EPA Method 5 particulate emission testing. These four ammonium sulfate manufacturing plants were then tested by EPA in order to evaluate control techniques currently used for controlling particulate emissions from ammonium sulfate dryers.

Presently throughout the ammonium sulfate industry, a variety of wet-scrubbing systems are employed to control ammonium sulfate particulate emissions. The majority of these are low-energy wet scrubbers, although medium-energy venturi scrubbers are being used with some ammonium sulfate dryers. For wet scrubbing systems in general, collection efficiency tends to increase with increased energy input, i.e., the higher the pressure drop, the higher the removal efficiency of particulates. This was borne out by analysis of EPA test results. For example, a synthetic ammonium sulfate plant, with a rotary drum drying facility controlled by a low-energy wet scrubber operating at a pressure drop of 15 centimeters (6 inches) W.G., showed a particulate collection efficiency of 97 percent. EPA test results from facilities with increased energy inputs, e.g., venturi scrubbers operating at pressure drops of 25.9 centimenters and 33 centimeters (10 and 13 inches) W.G. showed typically higher control efficiencies. In these latter cases, control efficiencies of 99.8 and 99.9 percent by weight were demonstrated with outlet particulate emission rates of 0.158 kg/Mg and 0.156 kg/Mg of ammonium sulfate production, respectively, at a synthetic ammonium sulfate plant using a rotary dryer and a caprolactam by-product ammonium sulfate plant using a fluidized bed dryer.

Additional emission test data on wet scrubbing control units have been provided by ammonium sulfate plant operators. At one facility, test results using EPA Method 5 show an average particulate emission rate of 0.135 kg/Mg of ammonium sulfate production. The facility, a caprolactam ammonium sulfate plant with a fluidized bed dryer, is controlled by a centrifugal scrubber preceded by a series of cyclones. The scrubber operates at 34 centimeters (13.4 inches) W.G. pressure drop.

Alternative emission control techniques were also examined. The one dry ammonium sulfate particulate control system in use (a fabric filter unit) was tested by EPA because it represents a unique application of this control method in the ammonium sulfate industry. The facility, a synthetic ammonium sulfate plant using a rotary dryer, did achieve a low mass emission rate, 0.007 kg/Mg (0.014 lb/ton); however, this emission rate is not considered representative of a typical ammonium sulfate facility. For example, the baghouse in use was originally designed for another application, and the gas flow rate to this unit is appreciably lower than normal direct-fired gas flow. This constraint on gas flow rate, by restricting the ratio of dryer exhaust gas-to-product rate, results in a significantly lower uncontrolled inlet emission rate than most other dryers used in the industry. In fact, the fabric filter inlet uncontrolled particulate emission rate was 0.41 kg/Mg of production, while those of facilities controlled by venturi scrubbers were 110 kg/Mg and 77 kg/Mg. This represents an uncontrolled mass emission difference in the range of two orders of magnitude. Thus, comparison of the outlet mass emissions for this facility with those of the other facilities tested is, in this situation, somewhat misleading.

Regulatory Options

Review of the performance of the emission control techniques led to the identification of two regulatory options. The two options are based on emission control techniques representative of two distinct levels of control. Each option specifies numerical emission limits for ammonium sulfate dryers applicable to the three major sectors of the ammonium sulfate industry. Option I is equivalent to no additional regulatory action. For this option, particulate emission levels would be set by existing SIP regulations, typically in the range of 0.71 kg/Mg to 1.3 kg/Mg of ammonium sulfate production. This option is characterized by the use of a low energy wet scrubber to meet the required emission limit, a reduction of 97 to 98 percent. Option II, based on the use of a venturi scrubber or fabric filter, would set an emission limit of 0.15 kilogram of particulate per megagram of ammonium sulfate production. As applied to the ammonium sulfate industry, both the venturi scrubber and the fabric filter control systems are capable of greater than 99.9 percent control efficiency. Option II therefore represents the most stringent control level that can be met by all segments of the ammonium sulfate industry.

Using model plants for the new, modified, and reconstructed ammonium sulfate facilities, the environmental impacts, energy impacts, and economic impacts of each regulatory option were analyzed and compared. Each ammonium sulfate manufacturing sector is unique from a technical standpoint. Dryer types and sizes, gas-to-product flow rates, and uncontrolled particulate emission rates vary from one sector to another and often within each sector. For these reasons it was apparent that no single model plant could adequately characterize the ammonium sulfate industry. Accordingly, several model dryers were specified in terms of the following parameters: Production rate, dryer types, exhaust gas flow rates, emission rates, stack height, stack diameter, and exit gas temperatures. The evaluation of these parameters may be found in Chapters 6, 7, and 8 of the document, "Ammonium Sulfate Manufacture—Background Information for Proposed Emission Standards."

Under Option I, annual nationwide particulate emissions from new, modified, and reconstructed ammonium sulfate manufacturing plants would increase by about 670 Mg/year (737 tons/year) between 1980 and 1985. Under Option II, nationwide particulate emissions would increase by 131 Mg/year (144 tons/year) during the same period. This represents a reduction of about 80 percent in the particulate emissions emitted under Option I, a typical SIP regulation.

Dispersion analysis under "worst case" atmospheric and meteorological conditions shows that the maximum 24-hour concentration of particulates in the vicinity of a new, modified, and reconstructed ammonium sulfate plant would be reduced by a factor of 80

percent (from 224 to 47.4 micrograms per cubic meter) by controlling to Option II rather than the SIP emission limit. The maximum annual average is reduced from 29.1 to 6.15 micrograms per cubic meter under Option II.

Effluent guidelines set forth in 40 CFR 418.60 limit water pollution from synthetic and coke oven ammonium sulfate plants. In the caprolactam by-product ammonium sulfate plant, water is removed in the crystallizer, condensed and recycled to the principal plant for plant use. The addition of a scrubber for emission control would not create a water pollution problem since all scrubbing liquor would be recycled to the process. The use of a baghouse would not create a water pollution problem since it is a dry collection system. Consequently, the water pollution impact of Option II would be zero.

The ammonium sulfate plants generate no solid waste as part of the process since all collected ammonium sulfate is recycled to the process. Furthermore, no significant increase in noise level is anticipated under Option II.

For typical plants in the ammonium sulfate manufacturing industry, an increase in energy consumption would result from compliance with Option II. The energy required, in excess of that required by a typical SIP regulation, to control caprolactam by-product ammonium sulfate plants to the level of Option II would be 8.8 gigawatt hours of electricity per year in 1985 using venturi scrubbers. The overall energy increase would amount to less than 0.65 percent of the total energy required to operate a typical caprolactam by-product ammonium sulfate plant. For synthetic and for coke oven by-product ammonium sulfate plants, the 1985 incremental energy increase would be 0.61 and 0.14 gigawatt hours per year, respectively, or less than a 0.1 percent increase. The total industry-wide energy increment would be 9.5 gigawatt hours per year in 1985. This figure indicates that Option II would not significantly increase energy consumption at ammonium sulfate plants and would have minimal impact on national energy consumption.

Economic analysis also indicates that the impact of Option II is minimal. The capital cost of the installed emission control equipment necessary to meet Option II, on all new, modified, and reconstructed ammonium sulfate facilities coming on line nationwide during the period 1980 to 1985, would be about $958,000. The total annualized cost of operating this equipment during the same period would be about $480,200. These costs are considered reasonable, and are not expected to prevent or hinder expansion or continued production in the ammonium sulfate manufacturing industry. The incremental cost necessary to offset the cost of meeting Option II would be about 0.01 percent of the wholesale price of ammonium sulfate.

Consideration of the beneficial impact on national particulate emissions; the lack of water pollution impact or solid waste impact; the minimal energy impact; the reasonable cost impact; and the general availability of demonstrated emission control technology leads to the selection of Option II as the basis for the proposed standards of performance for ammonium sulfate dryers.

Selection of Opacity Emission Limits

The best indirect method of ensuring proper operation and maintenance of emission control equipment is the specification of exhaust gasopacity limits. Determining an acceptable exhaust gas opacity limit is possible because opacity levels were evaluated for ammonium sulfate dryers during EPA tests; therefore, the data base for the particulate standards includes information on opacity. Ammonium sulfate dryers were observed to have no opacity readings greater than 15 percent opacity, and a total of 90 minutes of opacity of less than or equal to 15 percent but greater than 10 percent during observation periods of 180, 120, 438, and 408 minutes (1146 minutes total). Therefore, a standard of 15 percent opacity is proposed for all affected facilities to ensure proper operation and maintenance of control systems on a day-to-day basis.

Selection of Performance Test Methods

The use of EPA Reference Method 5—"Determination of Particulate Emissions from Stationary Sources" would be required to determine compliance with the mass standards for particulate matter emissions. Results of performance tests using Method 5 conducted by EPA on existing ammonium sulfate dryers comprise a major portion of the data base used in the development of the proposed standards. EPA Reference Method 5 has been shown to provide a representative measurement of particulate matter emissions. Therefore, it is included for the purpose of determining compliance with the proposed standards.

Method 5 calculations require imput data obtained from three other EPA test methods conducted previous to the performance of Method 5. Method 1, "Sample and Velocity Traverse for Stationary Sources," must be used to obtain representative measurements of pollutant emissions. The average gas velocity in the exhaust stack is measured by conducting Method 2, "Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)." The analysis of gas composition is measured by conducting Method 3, "Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight." These three tests provide data necessary in Method 5 for determining concentration of particulate matter in the dryer exhaust. All opacity observations would be made in accordance with the procedures established in EPA Method 9 for stack emissions.

Since the proposed standards are expressed as mass of emissions per unit mass of ammonium sulfate production, it will be necessary to quantify production rate in addition to measuring particulate emissions. Ammonium sulfate production in megagrams shall be determined by direct measurement using product weigh scales or computed from a material balance. A material balance computation based on the chemical reactions used in the formation of ammonium sulfate is an acceptable method of determining production rate since the formation reactions used in all industrial sectors are quantitative and irreversible.

If a material balance is used, the ammonium sulfate production rate for synthetic and coke oven by-product ammonium sulfate plants shall be calculated from the metered sulfuric acid feed rate to the reactor/crystallizer. For caprolactam by-product ammonium sulfate plants, production rate shall be determined from the oximation ammonium sulfate solution flow rate and the oleum flow to the caprolactam rearrangement reaction.

Selection of Monitoring Requirements

To further ensure that installed emission control systems continuously comply with standards of performance through proper operation and maintenance, monitoring requirements are generally included in standards of performance. In the case of ammonium sulfate dryers, the most straightforward means of ensuring proper operation and maintenance is to require monitoring of actual particulate emissions released to the atmosphere. Currently, however, there are no continuous particulate monitors in operation for ammonium sulfate dryers; and resolution of the sampling problems and development of performance specifications for continuous particulate monitors would entail a major development program. For these reasons, continuous monitoring of

particulate emissions from ammonium sulfate dryers is not required by the proposed standards.

The best indirect method of monitoring proper operation and maintenance of emission control equipment is to continuously monitor the opacity of the exhaust gas. The proposed opacity limit for ammonium sulfate dryers is 15 percent. However, in the case of ammonium sulfate dryers, the character of the exhaust gas when wet scrubbers are used for emission reduction precludes the use of continuous in-stack opacity monitors. Where condensed moisture is present in the exhaust gas stream, in-stack continuous monitoring of opacity is not feasible; water droplets and steam can interfere with operation of the monitoring instrument. Since most affected facilities are likely to use wet scrubbers, continuous monitoring of opacity is not required by the proposed standards.

An alternative to particulate or opacity monitors is the use of a pressure drop monitor as a means of ensuring proper operation and maintenance of emission control equipment. For venturi scrubbers, particulate removal efficiency is related directly to pressure drop across the venturi; the higher the pressure drop, the higher the removal efficiency. For fabric filters, pressure drop is used as an indicator of excessive filter resistance or damaged filter media. Therefore, in order to provide a continuous indicator of emission control equipment operation and maintenance, the proposed standards would require that the owner or operator of any ammonium sulfate manufacturing plant subject to the standards install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the process emission control system. The monitoring device shall have an accuracy of ±5 percent over its operating range.

The proposed standards would also require the owner or operator of any ammonium sulfate manufacturing plant subject to the standards to install, calibrate, maintain, and operate flow monitoring devices necessary to determine the mass flow of ammonium sulfate feed material to the process. The flow monitoring device shall have an accuracy of ±5 percent over its operating range. The ammonium sulfate feed streams are: for synthetic and coke oven by-product ammonium sulfate plants, the sulfuric acid feed stream to the reactor/crystallizer; for caprolactam by-product ammonium sulfate plants, the oximation ammonium sulfate stream to the ammonium sulfate plant and the oleum stream to the caprolactam rearrangement reaction.

Records of pressure drop and calibration measurements would have to be retained for at least 2 years following the date of the measurements by owners and operators subject to this subpart. This requirement is included under § 60.7(d) of the general provisions of 40 CFR Part 60.

Public Hearing

A public hearing will be held to discuss these proposed standards in accordance with section 307(d)(5) of the Clean Air Act. Persons wishing to make oral presentations should contact EPA at the address given in the ADDRESSES section of this preamble. Oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement with EPA before, during, or within 30 days after the hearing. Written statements should be addressed to the Docket address given in the ADDRESSES section of this preamble.

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at EPA's Central Docket Section in Washington, D.C. (See ADDRESSES section of this preamble.)

Docket

The docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The principal purposes of the docket are: (1) To allow interested persons to identify and locate documents so that they can intelligently and effectively participate in the rulemaking process, and (2) to serve as the record for judicial review. The docket requirement is discussed in section 307(d) of the Clean Air Act.

Miscellaneous

As prescribed by section 111 of the Act, this proposal of standards has been preceded by the Administrator's determination that emissions from ammonium sulfate manufacturing plants contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare (40 CFR 60.16, 44 FR 49222, August 21, 1979). In accordance with section 117 of the Act, publication of these proposed standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies. The Administrator will welcome comments on all aspects of the proposed regulation, including economic and technological issues.

It should be noted that standards of performance for new stationary sources established under section 111 of the Clean Air Act reflect:

> • • • application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. (section 111(a)(1))

Although there may be emission control technology available that is capable of reducing emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance because of costs associated with its use. Accordingly, these standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act requires (or has the potential for requiring) the imposition of a more stringent emission standard in several situations.

For example, applicable costs do not necessarily play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources locating in nonattainment areas; i.e., those areas where statutorily-mandated health and welfare standards are being violated. In this respect, section 173 of the Act requires that new or modified sources constructed in an area which exceeds the national ambient air quality standard (NAAQS) must reduce emissions to the level which reflects the "lowest achievable emission rate" (LAER), as defined in section 171(3), for such category of source. The statute defines LAER as that rate of emissions based on the following, whichever is more stringent:

> (A) The most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or
>
> (B) The most stringent emission limitation which is achieved in practice by such class or category of source.

In no event can the emission rate exceed any applicable new source performance standard (section 171(3)).

A similar situation may arise under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require that certain sources (referred to in section 169(1)) employ "best available control technology" (as defined in section 169(3)) for all pollutants regulated under the Act. "Best available control technology" (BACT) must be determined on a case-by-case basis,

taking energy, environmental, and economic impacts and other cost into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the Act.

In all events, State Implementation Plans (SIPs) approved or promulgated under section 110 of the Act must provide for the attainment and maintenance of the national ambient air quality standards (NAAQS) designed to protect public health and welfare. For this purpose, SIP's must in some cases require greater emission reductions than those required by standards of performance for new sources.

Finally, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possiblility in planning for such facilities.

EPA will review this regulation four years from the date of promulgation. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, and improvements in emission control technology.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance promulgated under section 11(b) of the Act. An economic impact assessment was prepared for the proposed regulations and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the proposed standards to ensure that the proposed standards would represent the best system of emission reduction considering costs. The economic impact assessment is included in the background information document.

Dated: January 28, 1980.

Douglas M. Costle,

Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

It is proposed that 40 CFR Part 60 be amended by adding a new Subpart P as follows:

Subpart PP—Standards of Performance for Ammonium Sulfate Manufacture

Sec.

60.420 Applicability and designation of affected facilty.
60.421 Definitions.
60.422 Standards for particulate matter.
60.423 Monitoring of operations.
60.424 Test methods and procedures.

Authority: Sec. 111, 301(a), Clean Air Act as amended, (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

Subpart PP—Standards of Performance for Ammonium Sulfate Manufacture

§ 60.420 Applicability and designation of affected facility.

The affected facility to which the provisions of this subpart apply is each ammonium sulfate dryer with an ammonium sulfate manufacturing plant in the caprolactam by-product, synthetic, and coke oven by-product sectors of the ammonium sulfate industry.

§ 60.421 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

(a) "Ammonium sulfate manufacturing plant" means any plant which produces ammonium sulfate.

(b) "Ammonium sulfate dryer" means a unit or vessel in which ammonium sulfate is charged for the purpose of reducing the moisture content of the product using a heating gas stream. The unit includes foundations, superstructure, material charger systems, exhaust systems, and integral control systems and instrumentation.

(c) "Caprolactam by-product ammonium sulfate manufacturing plant" means any plant which produces ammonium sulfate as a by-product from process streams generated during caprolactam manufacture.

(d) "Synthetic ammonium sulfate manufacturing plant" means any plant which produces ammonium sulfate by direct combination of ammonia and sulfuric acid.

(e) "Coke oven by-product ammonium sulfate manufacturing plant" means any plant which produces ammonium sulfate by reacting sulfuric acid with ammonia recovered as a by-product from the manufacture of coke.

(f) "Ammonium sulfate feed material streams" means the sulfuric acid feed stream to the reactor/crystallizer for synthetic and coke oven by-product ammonium sulfate manufacturing plants; and means the oximation ammonium sulfate stream to the ammonium sulfate manufacturing plant and the oleum stream to the caprolactam rearrangement reaction for caprolactam by-product ammonium sulfate manufacturing plants.

§ 60.422 Standards for particulate matter.

On or after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator of an ammonium sulfate dryer subject to the provisions of this subpart shall cause to be discharged into the atmosphere, from any ammonium sulfate dryer, particulate matter at emission rates exceeding 0.15 kilogram of particulate per megagram of ammonium sulfate produced (0.30 pound of particulate per ton of ammonium sulfate produced) and exhaust gases with opacity of greater than 15 percent opacity.

§ 60.423 Monitoring of operations.

(a) The owner or operator of any ammonium sulfate manufacturing plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate flow monitoring devices which can be used to determine the mass flow of ammonium sulfate feed material streams to the process. The flow monitoring device shall have an accuracy of ± 5 percent over its range.

(b) The owner or operator of any ammonium sulfate manufacturing plant subject to the provisions of this subpart shall install, calibrate, maintain, and operate a monitoring device which continuously measures and permanently records the total pressure drop across the emission control system. The monitoring device shall have an accuracy of ± 5 percent over its operating range.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))

§ 60.424 Test methods and procedures.

(a) Reference methods in Appendix A of this part, except as provided in § 60.8(b), shall be used to determine compliance with § 60.422 as follows:

(1) Method 5 for the concentration of particulate matter.

(2) Method 1 for sample and velocity traverses.

(3) Method 2 for velocity and volumetric flow rate.

(4) Method 3 for gas analysis.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the volume shall be at least 1.50 dry standard cubic meters (53 dry standard cubic feet).

(c) for each run, the particulate emission rate, E, shall be computed as follows:

$$E = Q_{sd} \times C_s \div 1000$$

(1) E is the particulate emision rate (kg/hr),

(2) Q_{sd} is the average volumetric flow rate (dscm/hr) as determined by Method 2; and

(3) C_s is the average concentration (g/dscm) of particulate matter as determined by Method 5.

(d) For each run, the rate of ammonium sulfate production, P (Mg/hr), shall be determined by direct measurement using product weight scales or computed from a material balance. If production rate is determined by material balance, the following equations shall be used.

(1) For synthetic and coke oven by-product ammonium sulfate plants, the ammonium sulfate production rate shall be determined using the following equation:

$$P = A \times B \times C \times 0.0808$$

where:

P = Ammonium sulfate production rate in megagrams per hour.
A = Sulfuric acid flow rate to the reactor/crystallizer in liters per minute averaged over the time period taken to conduct the run.
B = Acid density (a function of acid strength and temperature) in grams per cubic centimeter.
C = Percent acid strength in decimal form.
0.0808 = Physical constant for conversion of time, volume, and mass units.

(2) For caprolactam by-product ammonium sulfate plants the ammonium sulfate production rate shall be determined using the following equation:

$$P = [D \times E \times F \times (0.8612)] + [G \times H \times I \times (1.1620)]$$

where:

P = Production rate of caprolactam by-product ammonium sulfate in megagrams per hour.
D = Oximation ammonium sulfate process stream flow rate in liters per minute averaged over the time period taken to conduct the run.
E = Density of the process stream solution in grams per liter.
F = Percent ammonium sulfate in the process solution in decimal form.
G = Oleum flow rate to the rearrangement reaction in liters per minute averaged over the time period taken to conduct the run
H = Density of oleum in grams per liter.
I = Equivalent sulfuric acid percent of the oleum in decimal form.
0.8612 = Physical constant for conversion of time and mass units.
1.1620 = Physical constant for conversion of time and mass units.

(e) For each run, the dryer emission rate shall be computed as follows:

$$R = E/P$$

where:

(1) R is the dryer emission rate (kg/Mg);

(2) E is the particulate emission rate (kg/hr) from (c) above; and

(3) P is the rate of ammonium sulfate production (Mg/hr) from (d) above.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 7414))

[FR Doc 80-3593 Filed 2-1-80; 8:45 am]
BILLING CODE 6560-01-M

ENVIRONMENTAL PROTECTION AGENCY

■

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

CONTINUOUS MONITORING PERFORMANCE SPECIFICATIONS

APPENDIX B

40 CFR Part 60

[FRL 1276-4]

Standards of Performance for New Stationary Sources; Continuous Monitoring Performance Specifications

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed Revisions.

SUMMARY: On October 6, 1975 (40 FR 46250), the EPA promulgated revisions to 40 CFR Part 60, Standards of Performance for New Stationary Sources, to establish specific requirements pertaining to continuous emission monitoring. An appendix to the regulation contained Performance Specifications 1 through 3, which detailed the continuous monitoring instrument performance and equipment specifications, installation requirements, and test and data computation procedures for evaluating the acceptability of continuous monitoring systems. Since the promulgation of these performance specifications, the need for a number of changes which would clarify the specification test procedures, equipment specifications, and monitoring system installation requirements has become apparent. The purpose of the revisions is to incorporate these changes into Performance Specifications 1 through 3.

The proposed revisions would apply to all monitoring systems currently subject to performance specifications 1, 2, or 3, including sources subject to Appendix P to 40 CFR Part 51.

DATES: Comments must be received on or before December 10, 1979.

ADDRESSES: *Comments.* Comments should be submitted (in duplicate if possible) to the Central Docket Section (A-130), Attn: Docket No. OAQPS-79-4, U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460.

Docket. Docket No. OAQPS-79-4, containing material relevant to this rulemaking, is located in the U.S. Environmental Protection Agency, Central Docket Section, Room 2903B, 401 M Street, S.W., Washington, D.C. The docket may be inspected between 8 A.M. and 4 P.M. on weekdays, and a reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5271.

SUPPLEMENTARY INFORMATION: Changes common to all three of the performance specifications are the clarification of the procedures and equipment specifications, especially the requirement for intalling the continuous monitoring sample interface and of the calculation procedure for relative accuracy. Specific changes to the specifications are as follows:

Performance Specification

1. The optical design specification for mean and peak spectral responses and for the angle of view and projection have been changed from "500 to 600 nm" range to "515 to 585 nm" range and from "5°" to "3°", respectively.

2. The following equipment specifications have been added:

a. Optical alignment sight indicator for readily checking alignment.

b. For instruments having automatic compensation for dirt accumulation on exposed optical surfaces, a compensation indicator at the control panel so that the permissible maximum 4 percent compensation can be determined.

c. Easy access to exposed optical surfaces for cleaning and maintenance.

d. A system for checking zero and upscale calibration (previously required in paragraph 60.13).

e. For systems with slotted tubes, a slotted portion greater than 90 percent of effluent pathlength (shorter slots are permitted if shown to be equivalent).

f. An equipment specification for the monitoring system data recorder resolution of <5 percent of full scale.

3. A procedure for determining the acceptability of the optical alignment sight has been specified; the optical alignment sight must be capable of indicating that the instrument is misaligned when an error of ± 2 percent opacity is caused by misalignment of the instrument at a pathlength of 8 meters.

4. Procedures for calibrating the attenuators used during instrument calibrations have been added; these procedures require the use of a laboratory spectrophotometer operating in the 400–700 nm range with a detector angle view of <10 degrees and an accuracy of 1 percent.

5. The following changes have been made to the procedures for the operational test period:

a. The requirement for an analog strip chart recorder during the performance tests has been deleted; all data are collected on the monitoring system data recorder.

b. Adjustment of the zero and span at 24-hour intervals during the drift tests is optional; adjustments are required only when the accumulated drift exceeds the 24-hour drift specification.

c. The amount of automatic zero compensation for dirt accumulation must be determined during the 24-hour zero check so that the actual zero drift can be quantified. The automatic zero compensation system must be operated during the performance test.

d. The requirement for offsetting the data recorder zero during the operational test period has been deleted.

e. Off the stack "zero alignment" of the instrument prior to installation is permitted.

Performance Specification 2

1. "Continuous monitoring system" has been redefined to include the diluent monitor, if applicable. The change requires that the relative accuracy of the system be determined in terms of the emission standard, e.g., mass per unit calorific value for fossil-fuel fired steam generators.

2. The applicability of the test procedures excludes single-pass, in-situ continuous monitoring systems. The procedures for determining the acceptability of these systems are evaluated on a case-by-case basis.

3. For extractive systems with diluent monitors, the pollutant and diluent monitors are required to use the same sample interface.

4. The procedure for determining the acceptability of the calibration gases has been revised, and the 20 percent (with 95 percent confidence interval) criterion has been changed to 5 percent of mean value with no single value being over 10 percent from the mean.

5. For low concentrations, a 10 percent of the applicable standard limitation for the relative accuracy has been added.

6. An equipment specification for the system data recorder requiring that the chart scale be readable to within <0.50 percent of full-scale has been added.

7. Instead of spanning the instrument at 90 percent of full-scale, a mid-level span is required.

8. The response time test procedure has been revised and the difference limitation between the up-scale and down-scale time has been deleted.

9. The relative accuracy test procedure has been revised to allow different tests (e.g., pollutant, diluent, moisture) during a 1-hour period to be correlated.

10. A low-level drift may be substituted for the zero drift test.

Performance Specification 3

1. The applicability of the test procedures has been limited to those monitors that introduce calibration gases directly into the analyzer and are used as diluent monitors. Alternative procedures for other types of monitors are evaluated on a case-by-case basis.

2. Other changes were made to be consistent with the revisions under *Performance Specification 2.*

The proposed revised performance specifications would apply to all sources subject to Performance Specifications 1, 2, or 3. These include sources subject to standards of performance that have already been promulgated and sources subject to Appendix P to 40 CFR Part 51. Since the purpose of these revisions is to clarify the performance specifications which were promulgated on October 6, 1975, not to establish more stringent requirements, it is reasonable to conclude that most continuous monitoring instruments which met and can continue to meet the October 6, 1975, specifications can also meet the revised specifications.

Under Executive Order 12044, the Environmental Protection Agency is required to judge whether a regulation is "significant" and therefore subject to the procedural requirements of the Order or whether it may follow other specialized development procedures. EPA labels these other regulations "specialized". I have reviewed this regulation and determined that it is a specialized regulation not subject to the procedural requirements of Executive Order 12044.

Dated: October 1, 1979.

Douglas M. Costle,

Administrator.

It is proposed to revise Appendix B, Part 60 of Chapter I, Title 40 of the Code of Federal Regulations as follows:

Appendix B—Performance Specifications

Performance Specification 1—Specifications and Test Procedures For Opacity Continuous Monitoring Systems in Stationary Sources

1. Applicability and Principle

1.1 Applicability. This Specification contains instrument design, performance, and installation requirements, and test and data computation procedures for evaluating the acceptability of continuous monitoring systems for opacity. Certain design requirements and test procedures established in the Specification may not be applicable to all instrument designs; equivalent systems and test procedures may be used with prior approval by the Administrator.

1.2 Principle. The opacity of particulate matter in stack emissions is continuously monitored by a measurement system based upon the principle of transmissometry. Light having specific spectral characteristics is projected from a lamp through the effluent in the stack or duct and the intensity of the projected light is measured by a sensor. The projected light is attenuated due to absorption and scatter by the particulate matter in the effluent; the percentage of visible light attenuated is defined as the opacity of the emission. Transparent stack emissions that do not attenuate light will have a transmittance of 100 percent or an opacity of zero percent. Opaque stack emissions that attenuate all of the visible light will have a transmittance of zero percent or an opacity of 100 percent.

This specification establishes specific design criteria for the transmissometer system. Any opacity continuous monitoring system that is expected to meet this specification is first checked to verify that the design specifications are met. Then, the opacity continuous monitoring system is calibrated, installed, an operated for a specified length of time. During this specified time period, the system is evaluated to determine conformance with the established performance specifications.

2. Definitions

2.1 Continuous Monitoring System. The total equipment required for the determination of opacity. The system consists of the following major subsystems:

2.1.1 Sample Interface. That portion of the system that protects the analyzer from the effects of the stack effluent and aids in keeping the optical surfaces clean.

2.1.2 Analyzer. That portion of the system that senses the pollutant and generates a signal output that is a function of the opacity.

2.1.3 Data Recorder. That portion of the system that processes the analyzer output and provides a permanent record of the output signal in terms of opacity. The data recorder may include automatic data reduction capabilities.

2.2 Transmissometer. That portion of the system that includes the sample interface and the analyzer.

2.3 Transmittance. The fraction of incident light that is transmitted through an optical medium.

2.4 Opacity. The fraction of incident light that is attenuated by an optical medium. Opacity (Op) and transmittance (Tr) are related by: $Op = 1 - Tr$.

2.5 Optical Density. A logarithmic measure of the amount of incident light attenuated. Optical density (D) is related to the transmittance and opacity as follows:

$$D = -\log_{10} Tr = -\log_{10}(1 - Op).$$

2.6 Peak Spectral Response. The wavelength of maximum sensitivity of the transmissometer.

2.7 Mean Spectral Response. The wavelength which bisects the total area under the effective spectral response curve of the transmissometer.

2.8 Angle of View. The angle that contains all of the radiation detected by the photodetector assembly of the analyzer at a level greater than 2.5 percent of the peak detector response.

2.9 Angle of Projection. The angle that contains all of the radiation projected from the lamp assembly of the analyzer at a level of greater than 2.5 percent of the peak illuminace.

2.10 Span Value. The opacity value at which the continuous monitoring system is set to produce the maximum data display output as specified in the applicable subpart.

2.11 Upscale Calibration Value. The opacity value at which a calibration check of the monitoring system is performed by simulating an upscale opacity condition as viewed by the receiver.

2.12 Calibration Error. The difference between the opacity values indicated by the continuous monitoring system and the known values of a series of calibration attenuators (filters or screens).

2.13 Zero Drift. The difference in continuous monitoring system output readings before and after a stated period of normal continuous operation during which no unscheduled maintenance, repair, or adjustment took place and when the opacity (simulated) at the time of the measurements was zero.

2.14 Calibration Drift. The difference in the continuous monitoring system output readings before and after a stated period of normal continuous operation during which no unscheduled maintenance, repair, or adjustment took place and when the opacity (simulated) at the time of the measurements was the same known upscale calibration value.

2.15 Response Time. The amount of time it takes the continuous monitoring system to display on the data recorder 95 percent of a step change in opacity.

2.16 Conditioning Period. A period of time (168 hours minimum) during which the continuous monitoring system is operated without unscheduled maintenance, repair, or adjustment prior to initiation of the operational test period.

2.17 Operational Test Period. A period of time (168 hours) during which the continuous monitoring system is expected to operate within the established performance specifications without any unscheduled maintenance, repair, or adjustment.

2.18 Pathlength. The depth of effluent in the light beam between the receiver and the transmitter of a single-pass transmissometer, or the depth of effluent between the transceiver and reflector of a double-pass transmissometer. Two pathlengths are referenced by this Specification as follows:

2.18.1 Monitor Pathlength. The pathlength at the installed location of the continuous monitoring system.

2.18.2 Emission Outlet Pathlength. The pathlength at the location where emissions are released to the atmosphere.

3. Apparatus

3.1 Continuous Monitoring System. Use any continuous monitoring system for opacity which is expected to meet the design specifications in Section 5 and the performance specifications in Section 7. The data recorder may be an analog strip chart recorder type or other suitable device with an input signal range compatible with the analyzer output.

3.2 Calibration Attenuators. Use optical filters with neutral spectral characteristics or screens known to produce specified optical densities to visible light. The attenuators must be of sufficient size to attenuate the entire light beam of the transmissometer. Select and calibrate a minimum of three attenuators according to the procedures in Sections 8.1.2. and 8.1.3.

3.3 Upscale Calibration Value Attenuator. Use an optical filter with neutral spectral characteristics, a screen, or other device that produces an opacity value (corrected for pathlength, if necessary) that is greater than the sum of the applicable opacity standard and one-fourth of the difference between the opacity standard and the instrument span value, but less than the sum of the opacity standard and one-half of the difference between the opacity standard and the instrument span value.

3.4 Calibration Spectrophotometer. To calibrate the calibration attenuators use a laboratory spectrophotometer meeting the following minimum design specification:

Parameter	Specification
Wavelength range	400–700 nm
Detector angle of view	≤ 10°
Accuracy	≤ 0.5 pct. transmittance

4. Installation Specifications

Install the continuous monitoring system where the opacity measurements are representative of the total emissions from the affected facility. Use a measurement path that represents the average opacity over the cross section. Those requirements can be met as follows:

4.1 Measurement Location. Select a measurement location that is (a) downstream from all particulate control equipment; (b) where condensed water vapor is not present; (c) accessible in order to permit routine maintenance; and (d) free of interference from ambient light (applicable only if transmissometer is responsive to ambient light).

4.2 Measurement Path. Select a measurement path that passes through the centroid of the cross section. Additional requirements or modifications must be met for certain locations as follows:

4.2.1 If the location is in a straight vertical section of stack or duct and is less than 4 equivalent diameters downstream or 1 equivalent diameter upstream from a bend, use a path that is in the plane defined by the bend.

4.2.2 If the location is in a vertical section of stack or duct and is less than 4 diameters downstream and 1 diameter upstream from a bend, use a path in the plane defined by the bend upstream of the transmissometer.

4.2.3 If the location is in a horizontal section of duct and is at least 4 diameters downstream from a vertical bend, use a path in the horizontal plane that is one-third the distance up the vertical axis from the bottom of the duct.

4.2.4 If the location is in a horizontal section of duct and is less than 4 diameters downstream from a vertical bend, use a path in the horizontal plane that is two-thirds the distance up the vertical axis from the bottom of the duct for upward flow in the vertical section, and one-third the distance up the vertical axis from the bottom of the duct for downward flow.

4.3 Alternate Locations and Measurement Paths. Other locations and measurement paths may be selected by demonstrating to the Administrator that the average opacity measured at the alternate location or path is equivalent (± 10 percent) to the opacity as measured at a location meeting the criteria of Sections 4.1 and 4.2. To conduct this demonstration, measure the opacities at the two locations or paths for a minimum period of two hours. The opacities of the two locations or paths may be measured at different times, but must be measured at the same process operating conditions.

5. Design Specifications

Continuous monitoring systems for opacity must comply with the following design specifications:

5.1 Optics.

5.1.1 Spectral Response. The peak and mean spectral responses will occur between 515 nm and 585 nm. The response at any wavelength below 400 nm or above 700 nm will be less than 10 percent of the peak spectral response.

5.1.2 Angle of View. The total angle of view will be no greater than 4 degrees.

5.1.3 Angle of Projection. The total angle of projection will be no greater than 4 degrees.

5.2 Optical Alignment sight. Each analyzer will provide some method for visually determining that the instrument is optically aligned. The system provided will be capable of indicating that the unit is misaligned when an error of ± 2 percent opacity occurs due to misalignment at a monitor pathlength of eight (8) meters.

5.3 Simulated Zero and Upscale Calibration System. Each analyzer will include a system for simulating a zero opacity and an upscale opacity value for the purpose of performing periodic checks of the transmissometer calibration while on an operating stack or duct. This calibration system will provide, as a minimum, a system check of the analyzer internal optics and all electronic circuitry including the lamp and photodetector assembly.

5.4 Access to External Optics. Each analyzer will provide a means of access to the optical surfaces exposed to the effluent stream in order to permit the surfaces to be cleaned without requiring removal of the unit from the source mounting or without requiring optical realignment of the unit.

5.5 Automatic Zero Compensation Indicator. If the monitoring system has a feature which provides automatic zero compensation for dirt accumulation on exposed optical surfaces, the system will also provide some means of indicating that a compensation of 4 ± 0.5 percent opacity has been exceeded; this indicator shall be at a location accessible to the operator (e.g., the data output terminal). During the operational test period, the system must provide some means for determining the actual amount of zero compensation at the specified 24-hour intervals so that the actual 24-hour zero drift can be determined (see Section 8.4.1).

5.6 Slotted Tube. For transmissometers that use slotted tubes, the length of the slotted portion(s) must

be equal to or greater than 90 percent of the monitor pathlength, and the slotted tube must be of sufficient size and orientation so as not to interfere with the free flow of effluent through the entire optical volume of the transmissometer photodetector. The manufacturer must also show that the transmissometer uses appropriate methods to minimize light reflections; as a minimum, this demonstration shall consist of laboratory operation of the transmissometer both with and without the slotted tube in position. Should the operator desire to use a slotted tube design with a slotted portion equal to less than 90 percent of the monitor pathlength, the operator must demonstrate to the Administrator that acceptable results can be obtained. As a minimum demonstration, the effluent opacity shall be measured using both the slotted tube instrument and another instrument meeting the requirement of this specification but not of the slotted tube design. The measurements must be made at the same location and at the same process operating conditions for a minimum period of two hours with each instrument. The shorter slotted tube may be used if the average opacity measured is equivalent (± 10 percent) to the opacity measured by the non-slotted tube design.

6. Optical Design Specifications Verifciation Procedure.

These procedures will not be applicable to all designs and will require modification in some cases; all modifications are subject to the approval of the Administrator.

Test each analyzer for conformance with the design specifications of Sections 5.1 and 5.2 or obtain a certificate of conformance from the analyzer manufacturer as follows:

6.1 Spectral Response. Obtain detector response, lamp emissivity and filter transmittance data for the components used in the measurement system from their respective manufacturers.

6.2 Angle of View. Set up the receiver as specified by the manufacturer's written instructions. Draw an arc with radius of 3 meters in the horizontal direction. Using a small (less than 3 centimeters) non-directional light source, measure the receiver response at 4-centimeter intervals on the arc for 24 centimeters on either side of the detector centerline. Repeat the test in the vertical direction.

6.3 Angle of Projection. Set up the projector as specified by the manufacturer's written instructions. Draw an arc with radius of 3 meters in the horizontal direction. Using a small (less than 3 centimeters) photoelectric light detector, measure the light intensity at 4-centimeter intervals on the arc for 24 centimeters on either side of the light source centerline of projection. Repeat the test in the vertical direction.

6.4 Optical Alignment Sight. In the laboratory set up the instrument as specified by the manufacturers written instructions for a monitor pathlength of 8 meters. Assure that the instrument has been properly aligned and that a proper zero and span have been obtained. Insert an attenuator of 10 percent (nominal) opacity into the instrument pathlength. Slowly misalign the projector unit until a positive or negative shift of two percent opacity is obtained by the data recorder. Then, following the manufacturer's written instructions, check the alignment and assure that the alignment procedure does in fact indicate that the instrument is misaligned. Realign the instrument and follow the same procedure for checking misalignment of the receiver or retroreflector unit.

6.5 Manufacturer's Certificate of Conformance (Alternative to above). Obtain from the manufacturer a certificate of conformance which certifies that the first analyzer randomly sampled from each month's production was tested according to Sections 6.1 through 6.3 and satisfactorily met all requirements of Section 5 of this Specification. If any of the requirements were not met, the certificate must state that the entire month's analyzer production was resampled according to the military standard 105D sampling procedure (MIL-STD-105D) inspection level II; was retested for each of the applicable requirements under Section 5 of this Specification; and was determined to be acceptable under MIL-STD-105D procedures, acceptable quality level 1.0. The certificate of conformance must include the results of each test performed for the analyzer(s) sampled during the month the analyzer being installed was produced.

7. Performance Specifications

The opacity continuous monitoring system performance specifications are listed in Table 1-1.

Table 1-1.—*Performance specifications*

Parameter	Specifications
1 Calibration error [a]	≤ 3 pct opacity
2 Response time	≤ 10 seconds
3 Conditioning period [b]	≥ 168 hours
4 Operational test period [b]	≥ 168 hours
5 Zero drift (24-hour) [a]	≤ 2 pct opacity
6 Calibration drift (24-hour) [a]	≤ 2 pct opacity
7 Data recorder resolution	≤ 0.50 pct of full scale span value

[a] Expressed as sum of absolute mean and the 95 percent confidence interval

[b] During the conditioning and operational test periods the continuous monitoring system shall not require any corrective maintenance, repair, replacement, or adjustment other than that clearly specified as routine and required in the operation and maintenance manuals

8. Performance Specification Verification Procedure

Test each continuous monitoring system that conforms to the design specifications (Section 5) using the following procedures to determine conformance with the performance specifications of Section 7.

8.1 Preliminary Adjustments and Tests. Prior to installation of the system on the stack, perform these steps or tests at the affected facility or in the manufacturer's laboratory.

8.1.1 Equipment Preparation. Set up and calibrate the monitoring system for the monitor pathlength to be used in the installation as specified by the manufacturer's written instructions. If the monitoring system has automatic pathlength adjustment, follow the manufacturer's instructions to adjust the signal output from the analyzer to equivalent values based on the emission outlet pathlength. Set the span at the value specified in the applicable subpart. At this time perform the zero alignment by balancing the response of the continuous monitoring system so that the simulated zero check coincides with the actual zero check performed across the simulated monitor pathlength Then, assure that the upscale calibration value is within the required opacity range (Section 3.3).

8.1.2 Calibrated Attenuator Selection. Based on the span value specified in the applicable subpart, select a minimum of three calibrated attenuators (low, mid, and high range) using Table 1-2. If the system is operating with automatic pathlength compensation, calculates the attenuator values required to obtain a system response equivalent to the applicable values shown in Table 1-2, use equation 1-1 for the conversion. A series of filters with nominal optical density (opacity) values of 0.1(20), 0.2(37), 0.3(50), 0.4(60), 0.5(68), 0.6(75), 0.7(80), 0.8(84), 0.9(88), and 1.0(90) are commercially available Within this limitation of filter availability, select the calibrated

attenuators having the values given in Table 1-2 or having values closest to those calculated by Equation 1-1.

Table 1-2.—*Required Calibrated Attenuator Values (Nominal)*

Span value (percent opacity)	Calibrated attenuator optical density (equivalent opacity in parenthesis)		
	Low-range D_2	Mid-range	High-range
50	0.1 (20)	0.2 (37)	0.3 (50)
60	.1 (20)	.2 (37)	.3 (50)
70	.1 (20)	.3 (50)	.4 (60)
80	.1 (20)	.3 (50)	.6 (75)
90	.1 (20)	.4 (60)	.7 (80)
100	.1 (20)	.4 (60)	.9 (87½)

$$D_1 = D_2 (L_1/L_2) \qquad \text{Equation 1-1}$$

Where:

D_1 = Nominal optical density value of required mid, low, or high range calibration attenuators.

D_2 = Desired attenuator optical density output value from Table 1-2 at the span required by the applicable subpart.

L_1 = Monitor pathlength.

L_2 = Emission outlet pathlength.

8.1.3 Attenuator Calibration. Calibrate the required filters or screens using a laboratory spectrophotometer meeting the specifications of Section 3.4 to measure the transmittance in the 400 to 700 nm wavelength range; make measurements at wavelength intervals of 20 nm or less. As an alternate procedure use an instrument meeting the specifications of Section 3.4 to measure the C.I.E. Daylight$_C$ Luminous Transmittance of the attenuators. During the calibration procedure assure that a minimum of 75 percent of the total area of the attenuator is checked. The attenuator manufacturer must specify the period of time over which the attenuator values can be considered stable, as well as any special handling and storing procedures required to enhance attenuator stability. To assure stability, attenuator values must be rechecked at intervals less than or equal to the period of stability guaranteed by the manufacturer. However, values must be rechecked at least every 3 months. If desired, these stability checks may be performed on an instrument other than that initially used for the attenuator calibration (Section 3.4). However, if a different instrument is used, the instrument shall be a high quality laboratory transmissometer or spectrophotometer and the same instrument shall always be used for the stability checks. If a secondary instrument is to be used for stability checks, the value of the calibrated attenuator shall be measured on this secondary instrument immediately following calibration and prior to being used. If over a period time an attenuator value changes by more than ±2 percent opacity, it shall be recalibrated or replaced by a new attenuator.

If this procedure is conducted by the filter or screen manufacturer or independent laboratory, obtain a statement certifying the values and that the specified procedure, or equivalent, was used.

8.1.4 Calibration Error Test. Insert the calibrated attenuators (low, mid, and high range) in the transmissometer path at or as near to the midpoint as feasible. The attenuator must be placed in the measurement path at a point where the effluent will be measured; i.e., do not place the calibrated attenuator in the instrument housing. While inserting the attenuator, assure that the entire projected beam will pass through the attenuator and that the attenuator is inserted in a manner which minimizes interference from reflected light. Make a total of five nonconsecutive readings for each filter. Record the monitoring system output readings in percent opacity (see example Figure 1-1).

8.1.5 System Response Test. Insert the high-range calibrated attenuator in the transmissometer path five times and record the time required for the system to respond to 95 percent of final zero and high-range filter values (see example Figure 1-2).

8.2 Preliminary Field Adjustments. Install the continuous monitoring system on the affected facility according to the manufacturer's written instructions and perform the following preliminary adjustments:

8.2.1 Optical and Zero Alignment. When the facility is not in operation, conduct the optical alignment by aligning the light beam from the transmissometer upon the optical surface located across the duct or stack (i.e., the retroflector or photodetector, as applicable) in accordance with the manufacturer's instructions. Under clear stack conditions, verify the zero alignment (performed in Section 8.1.1) by assuring that the monitoring system response for the simulated zero check coincides with the actual zero measured by the transmissometer across the clear stack. Adjust the zero alignment, if necessary. Then, after the affected facility has been started up and the effluent stream reaches normal operating temperature, recheck the optical alignment. If the optical alignment has shifted realign the optics.

8.2.2 Optical and Zero Alignment (Alternative Procedure). If the facility is already on line and a zero stack condition cannot practicably be obtained, use the zero alignment obtained during the preliminary adjustments (Section 8.1.1) prior to installation of the transmissometer on the stack. After completing all the preliminary adjustments and tests required in Section 8.1, install the system at the source and align the optics, i.e., align the light beam from the transmissometer upon the optical surface located across the duct or stack in accordance with the manufacturer's instruction. The zero alignment conducted in this manner shall be verified and adjusted, if necessary, the first time the facility is not in operation after the operational test period has been completed.

8.3 Conditioning Period. After completing the preliminary field adjustments (Section 8.2), operate the system according to the manufacturer's instructions for an initial conditioning period of not less than 168 hours while the source is operating. Except during times of instrument zero and upscale calibration checks, the continuous monitoring system will analyze the effluent gas for opacity and produce a permanent record of the continuous monitoring system output. During this conditioning period there shall be no unscheduled maintenance, repair, or adjustment. Conduct daily zero calibration and upscale calibration checks, and, when accumulated drift exceeds the daily operating limits, make adjustments and/or clean the exposed optical surfaces. The data recorder shall reflect these checks and adjustments. At the end of the operational test period, verify that the instrument optical alignment is correct. If the conditioning period is interrupted because of source breakdown (record the dates and times of process shutdown), continue the 168-hour period following resumption of source operation. If the conditioning period is interrupted because of monitor failure, restart the 168-hour conditioning period when the monitor becomes operational.

8.4 Operational Test Period. After completing the conditioning period operate the system for an additional 168-hour period. It is not necessary that the 168-hour operational test period immediately follow the 168-hour conditioning period. Except during times of instrument zero and upscale calibration checks, the continuous monitoring system will analyze the effluent gas for opacity and will produce a permanent record of the continuous monitoring system output. During this period, there will be no unscheduled maintenance, repair, or adjustment. Zero and calibration adjustments, optical surface cleaning, and optical realignment may be performed (optional) only at 24-hour intervals or at

such shorter intervals as the manufacturer's written instructions specify. Automatic zero and calibration adjustments made by the monitoring system without operator intervention or initiation are followable at any time. If the operational test period is interrupted because of source breakdown, continue the 168-hour period following resumption of source operation. If the test period is interrupted because of monitor failure, restart the 168-hour period when the monitor becomes operational. During the operational test period, perform the following test procedures:

8.4.1 Zero Drift Test. At the outset of the 168-hour operational test period, record the initial simulated zero and upscale opacity readings (see example Figure 1-3). After each 24-hour interval check and record the final zero reading before any optional or required cleaning and adjustment. Zero and upscale calibration adjustments, optical surface cleaning, and optical realignment may be performed only at 24-hour intervals (or at such shorter intervals as the manufacturer's written instructions specify) but are optional. However, adjustments and/or cleaning must be performed when the accumulated zero calibration or upscale calibration drift exceeds the 24-hour drift specifications (±2 percent opacity). If no adjustments are made after the zero check the final zero reading is recorded as the initial reading for the next 24-hour period. If adjustments are made, the zero value after adjustment is recorded as the initial zero value for the next 24-hour period. If the instrument has an automatic zero compensation feature for dirt accumulation on exposed lens, and the zero value cannot be measured before compensation is entered then record the amount of automatic zero compensation for the final zero reading of each 24-hour period. (List the indicated zero values of the monitoring system in parenthesis.)

8.4.2 Upscale Drift Test. At each 24-hour interval, after the zero calibration value has been checked and any optional or required adjustments have been made, check and record the simulated upscale calibration value. If no further adjustments are made to the calibration system at this time, the final upscale calibration value is recorded as the initial upscale value for the next 24-hour period. If an instrument span adjustment is made, the upscale value after adjustment is recorded as the initial upscale for the next 24-hour period.

During the operational test period record all adjustments, realignments and lens cleanings.

9. Calculation, Data Analysis, and Reporting

9.1 Arithmetic Mean. Calculate the mean of a set of data as follows:

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i \qquad \text{Equation 2-1}$$

Where:

$\bar{x}$ = mean value.
n = number of data points.
Σx_i = algebraic sum of the individual measurements, x_i

9.2 Confidence Interval. Calculate the 95 percent confidence interval (two-sided) as follows:

$$C.I._{95} = \frac{t_{.975}}{n\sqrt{n-1}} \sqrt{n(\Sigma x_i^2) - (\Sigma x_i)^2} \qquad \text{Equation 2-2}$$

Where:

$C.I._{95}$ = 95 percent confidence interval estimate of the average mean value.
$t_{.975} = t(1-\alpha/2)$.

Table 1-3—*$t_{.975}$ Values*

n	$t_{.975}$	n	$t_{.975}$	n	$t_{.975}$
2	12 706	7	2 447	12	2 201
3	4 303	8	2 385	13	2 179
4	3 182	9	2 306	14	2 160
5	2 776	10	2 262	15	2 145
6	2 571	11	2 228	16	2 131

The values in this table are already corrected for n-1 degrees of Freedom. Use n equal to the number of data points.

9.3 Conversion of Opacity Values from Monitor Pathlength to Emission Outlet Pathlength. When the monitor pathlength is different than the emisson outlet pathlength, use either of the following equations to convert from one basis to the other (this conversion may be automatically calculated by the monitoring system):

$$\log(1-Op_2) = (L_2/L_1)\,\text{Log}\,(1-Op_1) \qquad \text{Equation 1-4}$$

$$D_2 = (L_2/L_1) \qquad \text{Equation 1-5}$$

Where:

Op_1 = opacity of the effluent based upon L_1
Op_2 = opacity of the effluent based upon L_2
L_1 = monitor pathlength
L_2 = emission outlet pathlength
D_1 = optical density of the effluent based upon L_1
D_2 = optical density of the effleunt based upon L_2

9.4 Spectral Response. Using the spectral data obtained in Section 6.1, develop the effective spectral response curve of the transmissometer. Then determine and report the peak spectral response wavelength, the mean spectral response wavelength, and the maximum response at any wavelength below 400 nm and above 700 nm expressed as a percentage of the peak response.

9.5 Angle of View. For the horizontal and vertical directions, using the data obtained in Section 6.2, calculate the response of the receiver as a function of viewing angle (21 centimeters of arc with a radius of 3 meters equal 4 degrees), report relative angle of view curves, and determine and report the angle of view.

9.6 Angle of Projection. For the horizontal and vertical directions, using the data obtained in Section 6.3, calculate the response of the photoelectric detector as a function of projection angle, report relative angle of projection curves, and determine and report the angle of projection.

9.7 Calibration Error. See Figure 1-1. If the pathlength is not adjusted by the measurement system, subtract the actual calibrated attenuator value from the value indicated by the measurement system recorder for each of the 15 readings obtained pursuant to Section 8.1.4. If the pathlength is adjusted by the measurement system subtract the "path adjusted" calibrated attenuator values from the values indecated by the measurement system recorder the "path adjusted" calibrated attenuator values are calculated using equation 1-4 or 1-5). Calculate the arithmetic mean difference and the 95 percent confidence interval of the five tests at each attenuator value using Equations 1-2 and 1-3. Calculate the sum of the absolute value of the mean difference and the 95 percent confidence interval for each of the three test attenuators; report these three values as the calibration error.

9.8 Zero and Upscale Calibration Drifts. Using the data obtained in Sections 8.4.1 and 8.4.2 calculate the zero and upscale calibration drifts. Then calculate the arithmetic means and the 95 percent confidence intervals using Equations 1-2 and 1-3. Calculate the sum of the absolute value of the mean and the 95 percent confidence interval and report these values as the 24-hour zero drift and the 24-hour calibration drift.

9.9 Response Time. Using the data collected in Section 8.1.5, calculate the mean time of the 10 upscale and downscale tests and report this value as the system response time.

9.10 Reporting. Report the following (summarize in tabular form where appropriate).

9.10.1 General Information.

a. Instrument Manufacturer.
b. Instrument Model Number.
c. Instrument Serial Number.

d. Person(s) responsible for operational and conditioning test periods and affiliation.

e. Facility being monitored.

f. Schematic of monitoring system measurement path location.

g. Monitor pathlength, meters.

h. Emission outlet pathlength, meters.

i. System span value, percent opacity.

j. Upscale calibration value, percent opacity.

k. Calibrated Attenuator values (low, mid, and high range), percent opacity.

9.10.2 Design Specification Test Results

a. Peak spectral response, nm.

b. Mean spectral response, nm.

c. Response above 700 nm, percent of peak.

d. Response below 400 nm, percent of peak.

e. Total angle of view, degrees.

f. Total angle of projection, degrees.

9.10.3 Operational Test Period Results.

a. Calibration error, high-range, percent opacity.

b. Calibration error, mid-range, percent opacity.

c. Calibration error, low-range, percent opacity.

d. Response time, seconds.

e. 24-hour zero drift, percent opacity.

f. 24-hour calibration drift, percent opacity.

g. Lens cleaning, clock time.

h. Optical alignment adjustment, clock time.

9.10.4 Statements. Provide a statement that the conditioning and operational test periods were completed according to the requirements of Sections 8.3 and 8.4. In this statement, include the time periods during which the conditioning and operational test periods were conducted.

9.10.5 Appendix. Provide the data tabulations and calculations for the above tabulated results.

9.11 Retest. If the continuous monitoring system operates within the specified performance parameters of Table 1-1, the operational test period will be successfully concluded. If the continuous monitoring system fails to meet any of the specified performance parameters, repeat the operational test period with a system that meets the design specifications and is expected to meet the performance specifications.

10. Bibliograpny.

10.1 "Experimental Statistics," Department of Commerce, National Bureau of Standards Handbook 91, 1963, pp. 3-31, paragraphs 3-3.1.4.

10.2 "Performance Specifications for Stationary-Source Monitoring Systems for Gases and Visible Emissions," Environmental Protection Agency, Research Triangle Park, N. C., EPA-650/2-74-013, January 1974.

Person Conducting Test _____ Analyzer Manufacturer _____

Affiliation _____ Model/Serial No. _____

Date _____ Location _____

Monitor Pathlength, L_1 _____ Emission Outlet Pathlength, L_2 _____

Monitoring System Output Pathlength Corrected? Yes ___ No ___

Calibrated Neutral Density Filter Values

Actual Optical Density (Opacity):

Low Range _____(_____)

Mid Range _____(_____)

High Range _____(_____)

Path Adjusted Optical Density (opacity)

Low Range _____(_____)

Mid Range _____(_____)

High Range _____(_____)

Run Number	Calibration Filter Value (Path Adjusted Percent Opacity)	Instrument Reading (Percent Opacity)	Arithmetic Difference (% Opacity)		
			Low	Mid	High
1 – Low				–	–
2 – Mid			–		–
3 – High			–	–	
4 – Low				–	–
5 – Mid			–		–
6 – High			–	–	
7 – Low				–	–
8 – Mid			–		–
9 – High			–	–	
10–Low				–	–
11–Mid			–		–
12–High			–	–	
13–Low				–	–
14–Mid			–		–
15–High			–	–	–
			XXXX	XXXX	XXXX
Arithmetic Mean (Equation 1 – 2): A					
Confidence Interval (Equation 1 – 3): B					
Calibration Error |A| + |B|					

Figure 1 – 1. Calibration error determination

Person Conducting Test _____ Analyzer Manufacturer _____

Affiliation _____ Model/Serial No. _____

Date _____ Location _____

High Range Calibration Filter Value: Actual Optical Density (Opacity) _____(_____)

Path Adjusted Optical Density (Opacity) _____(_____)

Upscale Response Value (0.95 x filter value) _____percent opacity

Downscale Response Value (0.05 x filter value) _____percent opacity

Upscale	1	_____ seconds
	2	_____ seconds
	3	_____ seconds
	4	_____ seconds
	5	_____ seconds
Downscale	1	_____ seconds
	2	_____ seconds
	3	_____ seconds
	4	_____ seconds
	5	_____ seconds
	Average response	_____ seconds

Figure 1-2. Response Time Determination

Person Conducting Test _____ Analyzer Manufacturer _____

Affiliation _____ Model/ Serial No. _____

Date _____ Location _____

Monitor Pathlength, L_1 _____ Emission Outlet Pathlength, L_2 _____

Monitoring System Output Pathlength Corrected: ? Yes ____ No ____

Upscale Calibration Value : Actual Optical Density (Opacity) _____(____)

Path Adjusted Optical Density (Opacity) _____(____)

Date	Time		Percent Opacity										Alignment	
			Zero Reading*		Zero Drift	zero adjusted?	Upscale Calibration Reading		Upscale Drift	Calibration Drift	span adjusted?	lens cleaned?	checked?	adjusted?
	Begin	End	Initial A	Final B	C = B−A		Initial D	Final E	F = E−D	G = F−C**				
Arithmetic Mean (Eq. 1–2)														
Confidence Interval (Eq. 1–3)														
Zero Drift										Calibration Drift				

*without automatic zero compensation

**if zero was adjusted (manually or automatically) prior to upscale check, then use c = 0 .

Figure 1 - 3. Zero Calibration Drift Determination

Performance Specification 2—Specifications and Test Procedures for SO_2 and NO_x Continuous Monitoring Systems in Stationary Sources

1. Applicability and Principle

1.1 Applicability. This Specification contains (a) installation requirements, (b) instrument performance and equipment specifications, and (c) test procedures and data reduction procedures for evaluating the acceptability of SO_2 and NO_x continuous monitoring systems, which may include, for certain stationary sources, diluent monitors. The test procedures in item (c), above, are not applicable to single-pass, in-situ continuous monitoring systems; these systems will be evaluated on a case-by-case basis upon written request to the Administrator and alternative test procedures will be issued separately.

1.2 Principle. Any SO_2 or NO_x continuous monitoring system that is expected to meet this Specification is installed, calibrated, and operated for a specified length of time. During this specified time period, the continuous monitoring system is evaluated to determine conformance with the Specification.

2. Definitions

2.1 Continuous Monitoring System. The total equipment required for the determination of a gas concentration or a gas emission rate. The system consists of the following major sub-systems:

2.1.1 Sample Interface. That portion of a system that is used for one or more of the following: sample acquisition, sample transportation, sample conditioning, or protection of the monitor from the effects of the stack effluent.

2.1.2. Pollutant Analyzer. That portion of the system that senses the pollutant gas and generates an output that is proportional to the gas concentration.

2.1.3. Diluent Analyzer (if applicable). That portion of the system that senses the diluent gas (e.g., CO_2 or O_2) and generates an output that is proportional to the gas concentration.

2.1.4 Data Recorder. That portion of the monitoring system that provides a permanent record of the analyzer output. The data recorder may include automatic data reduction capabilities.

2.2 Types of Monitors. Continuous monitors are categorized as "extractive" or "in-situ," which are further categorized as "point," "multipoint," "limited-path," and "path" type monitors or as "single-pass" or "double-pass" type monitors.

2.2.1 Extractive Monitor. One that withdraws a gas sample from the stack and transports the sample to the analyzer.

2.2.2 In-situ Monitor. One that senses the gas concentration in the stack environment and does not extract a sample for analysis.

2.2.3 Point Monitor. One that measures the gas concentration either at a single point or along a path which is less than 10 percent of the length of a specified measurement line.

2.2.4 Multipoint Monitor. One that measures the gas concentration at 2 or more points.

2.2.5 Limited-Path Monitor. One that measures the gas concentration along a path, which is 10 to 90 percent of the length of a specified measurement line.

2.2.6 Path Monitor. One that measures the gas concentration along a path, which is greater than 90 percent of the length of a specified measurement line.

2.2.7 Single-Pass Monitor. One that has the transmitter and the detector on opposite sides of the stack or duct.

2.2.8 Double-Pass Monitor. One that has the transmitter and the detector on the same side of the stack or duct.

2.3 Span Value. The upper limit of a gas concentration measurement range which is specified for affected source categories in the applicable subpart of the regulations.

2.4 Calibration Gases. A known concentration of a gas in an appropriate diluent gas.

2.5 Calibration Gas Cells or Filters. A device which, when inserted between the transmitter and detector of the analyzer, produces the desired output level on the data recorder.

2.6 Relative Accuracy. The degree of correctness including analytical variations of the gas concentration or emission rate determined by the continuous monitoring system, relative to the value determined by the reference method(s).

2.7 Calibration Error. The difference between the gas concentration indicated by the continuous monitoring system and the known concentration of the calibration gas, gas cell, or filter.

2.8 Zero Drift. The difference in the continuous monitoring system output readings before and after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place and when the pollutant concentration at the time of the measurements was zero (i.e., zero gas, or zero gas cell or filter).

2.9 Calibration Drift. The difference in the continuous monitoring system output readings before and after a stated period of operation during which no unscheduled maintenance, repair or adjustment took place and when the pollutant concentration at the time of the measurements was a high-level value (i.e., calibration gas, gas cell or filter).

2.10 Response Time. The amount of time it takes the continuous monitoring system to display on the data recorder 95 percent of a step change in pollutant concentration.

2.11 Conditioning Period. A minimum period of time over which the continuous monitoring system is expected to operate with no unscheduled maintenance, repair, or adjustments prior to initiation of the operational test period.

2.12 Operational Test Period. A minimum period of time over which the continuous monitoring system is expected to operate within the established performance specifications with no unscheduled maintenance, repair or adjustment.

3. Installation Specifications

Install the continuous monitoring system at a location where the pollutant concentration measurements are representative of the total emissions from the affected facility and are representative of the concentration over the cross section. Both requirements can be met as follows:

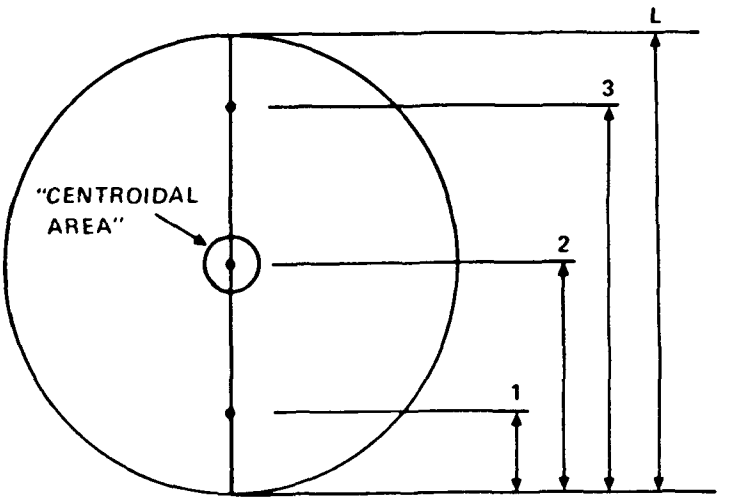
3.1 Measurement Location. Select an accessible measurement location in the stack or ductwork that is at least 2 equivalent diameters downstream from the nearest control device or other point at which a change in the pollutant concentration may occur and at least 0.5 equivalent diameters upstream from the effluent exhaust. Individual subparts of the regulations may contain additional requirements. For example, for steam generating facilities, the location must be downstream of the air preheater.

3.2 Measurement Points or Paths. There are two alternatives. The tester may choose either (a) to conduct the stratification check procedure given in Section 3.3 to select the point, points, or path of average gas concentration, or (b) to use the options listed below without a stratification check.

Note.—For the purpose of this section, the "centroidal area" is defined as a concentric area that is geometrically similar to the stack cross section and is no greater than 1 percent of the stack cross-sectional area.

3.2.1 SO_2 and NO_x Path Monitoring Systems. The tester may choose to centrally locate the sample interface (path) of the monitoring system on a measurement line that passes through the "centroidal area" of the cross section.

3.2.2 SO_2 and NO_x Multipoint Monitoring Systems. The tester may choose to space 3 measurement points along a measurement line that passes through the "centroidal area" of the stack cross section, at distances of 16.7, 50.0, and 83.3 percent of the way across it (see Figure 2-1).



POINT NO.	DISTANCE (% OF L)
1	16.7
2	50 0
3	83 3

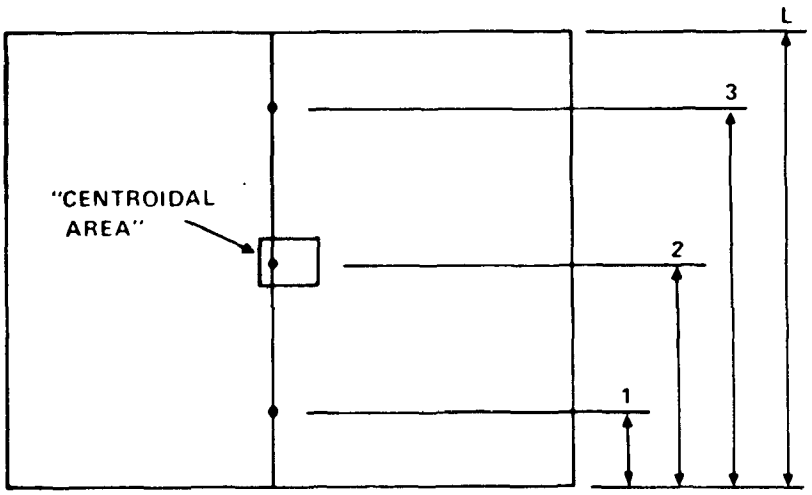


Figure 2-1. Location of an example measurement line (L) and measurement points.

The following sampling strategies, or equivalent, for measuring the concentrations at the 3 points are acceptable: (a) The use of a 3-probe or a 3-hole single probe arrangment, provided that the sampling rate in each of the 3 probes or holes is maintained within 10 percent of their average rate (This option requires a procedure, subject to the approval of the Administrator, to demonstrate that the proper sampling rate is maintained); or (b) the use of a traversing probe arrangement, provided that a measurement at each point is made at least once every 15 minutes and all 3 points are traversed and sampled for equal lengths of time within 15 minutes.

3.2.3 SO_2 Single-Point and Limited-Path Monitoring Systems. Provided that (a) no "dissimilar" gas streams (i.e., having greater than 10 percent difference in pollutant concentration from the average) are combined upstream of the measurement location, and (b) for steam generating facilities, a CO_2 or O_2 cotinuous monitor is installed in addition to the SO_2 monitor, according to the guidelines given in Section 3.1 or 3.2 of Performance Specification 3, the tester may choose to monitor SO_2 at a single point or over a limited path. Locate the point in or centrally locate the limited path over the "centroidal area." Any other location within the inner 50 percent of the stack cross-sectional area that has been demonstrated (see Section 3.4) to have a concentration within 5 percent of the concentration at a point within the "centroidal area" may be used.

3.2.4 NO_x Single-Point and Limited-Path Monitoring Systems. For NO_x monitors, the tester may choose the single-point or limited-path option described in Section 3.2.3 only in coal-burning steam generators (does not include oil and gas-fired units) and nitric acid plants, which have no dissimilar gas streams combining upstream of the measurement location.

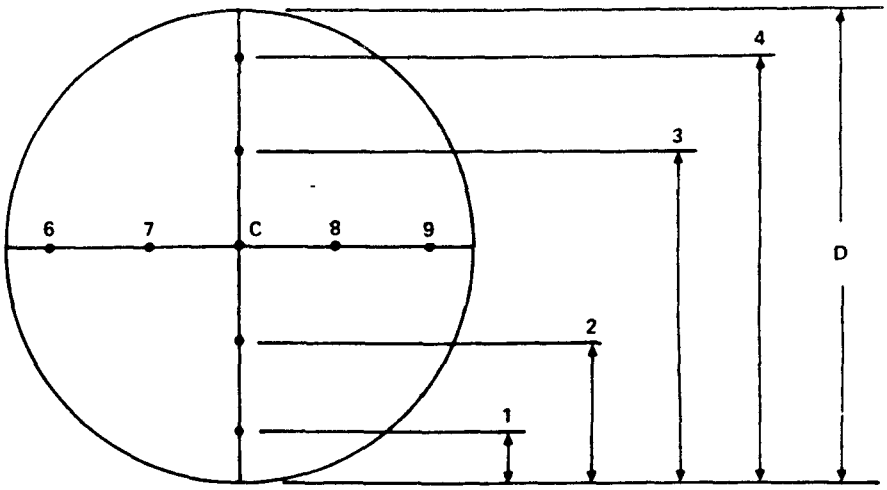
3.3 Stratification Check Procedure. Unless specifically approved in Section 3.2., conduct a stratification check and select the measurement point, points, or path as follows:

3.3.1 Locate 9 sample points, as shown in Figure 2-2, a or b. The tester may choose to use more than 9 points, provided that the sample points are located in a similar fashion as in Fgure 2-2.

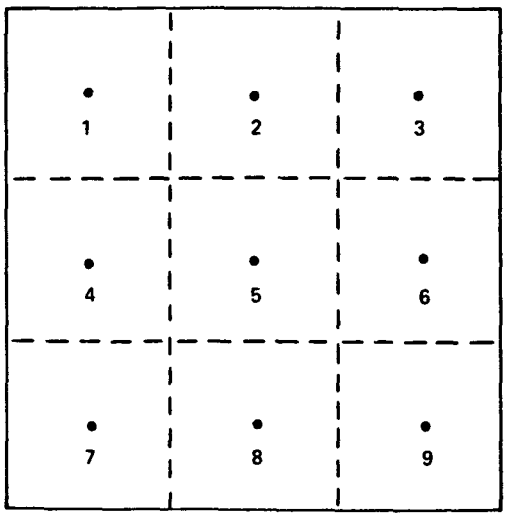
3.3.2 Measure at least twice the pollutant and, if applicable (as in the case of steam generators), CO_2 or O_2 concentrations at each of the sample points. Moisture need not be determined for this step. The following methods are acceptable for the measurements: (a) Reference Methods 3 (grab-sample), 6 or 7 of this part; (b) appropriate instrumental methods which give relative responses to the pollutant (i.e., the methods need not be absolutely correct), subject to the approval of the Administrator; or (c) alternative methods subject to the approval of the Administrator. Express all measurements, if applicable, in the units of the applicable standard.

3 3.3 Calculate the mean value and select a point, points, limited-path, or path which gives an equivalent value to the mean. The point or points must be within, and the limited-path or path must pass through, the inner 50 percent of the stack cross-sectional area. All other locations must be approved by the Administrator.

POINT NO.	DISTANCE (% OF D)
1, 9	10.0
2, 8	30.0
C	50.0
3, 7	70.0
4, 6	90.0



(a)



(b)

Figure 2-2. Location of 9 sampling points for stratification check.

3.4 Acceptability of Single Point or Limited Path Alternative Location. Any of the applicable measurement methods mentioned in Section 3.3.2, above, may be used. Measure the pollutant and, if applicable, CO_2 or O_2 concentrations at both the centroidal area and the alternative locations. Moisture need not be measured for this test. Collect a 21-minute integrated sample or 3 grab-samples, either at evenly spaced (7 ± 2 min.) intervals over 21 minutes or all within 3 minutes, at each location. Run the comparative tests either concurrently or within 10 minutes of each other. Average the results of the 3 grab-samples.

Repeat the measurements until a minimum of 3 paired measurements spanning a minimum of 1 hour of process operation are obtained. Determine the average pollutant concentrations at the centroidal area and the alternative locations. If applicable, convert the data in terms of the standard for each paired set before taking the average. The alternative sampling location is acceptable if each alternative location value is within ± 10 percent of the corresponding centroidal area value and if the average at the alternative location is within 5 percent of the average of the centroidal area.

4. Performance and Equipment Specifications

The continuous monitoring system performance and equipment specifications are listed in Table 2-1. To be considered acceptable, the continuous monitoring system must demonstrate compliance with these specifications using the test procedures of Section 6.

5. Apparatus

5.1 Continuous Monitoring System. Use any continuous monitoring system of SO_2 or NO_x which is expected to meet the specifications in Table 2-1. For sources which are required to convert the pollutant concentrations to other emission units using diluent gas measurements, the diluent gas continuous monitor, as described in Performance Specification 3 of this Appendix, is considered part of the continuous monitoring system. The data recorder may be an analog strip chart recorder type or other suitable device with an input signal range compatible with the analyzer output.

5.2 Calibration Gases. For continuous monitoring systems that allow the introduction of calibration gases to the analyzer, the calibration gases may be SO_2 in air or N_2, NO in N_2, and NO_2 in air or N_2. Two or more calibration gases may be combined in the same gas cylinder, except do not combine the NO and air. For NO_x monitoring systems that oxidize NO to NO_2, the calibration gases must be in the form of NO. Use three calibration gas mixtures as specified below:

5.2.1 High-Level Gas. A gas concentration that is equivalent to 80 to 90 percent of the span value.

Table 2-1.—*Continuous Monitoring System Performance and Equipment Specifications*

Parameter	Specification
1 Conditioning period [a]	≥168 hours
2 Operational test period [a]	≥168 hours.
3 Calibration error [b]	≤5 pct of each mid-level and high-level calibration value
4 Response time. ..	≤15 minutes (5 minutes for 3-point traversing probe arrangement).
5 Zero drift (2-hour) [b] [c]	≤2 pct of span value
6 Zero drift (24-hour) [b] [c]	≤2 pct of span value.
7 Calibration drift (2-hour) [b].	≤2 pct of span value.
8 Calibration drift (24-hour) [b]	≤2 5 pct of span value.
9 Relative accuracy [b]	≤20 pct of the mean value of reference method(s) test data in terms of emission standard or 10 percent of the applicable standard, whichever is greater
10 Calibration gas cells or filters	Must provide a check of all analyzer internal mirrors and lenses and all electronic circuitry including the radiation source and detector assembly which are normally use in sampling and analysis
11 Data recorder chart resolution	Chart scales must be readable to within ≤0 50 pct of full-scale
12 Extractive systems with diluent monitors	Must use the same sample interface to sample both the pollutant and diluent gases Place in series (diluent after pollutant analyzer) or use a "T " [a] During the conditioning and operational test periods, the continuous monitoring system shall not require any corrective maintenance, repair, replacement, or adjustment other than that clearly specified as routine and required in the operation and maintenance manuals [b] Expressed as the sum of the absolute mean value plus the 95 percent confidence interval of a series of tests divided by a reference value [c] A low-level (5-15 percent of span value) drift test may be substituted for the zero Drift tests

5.2.2 Mid-Level Gas. A gas concentration that is equivalent to 45 to 55 percent of the span value.

5.2.3 Zero Gas. A gas concentration of less than 0.25 percent of the span value. Ambient air may be used for the zero gas.

5.3 Calibration Gas Cells or Filters. For continuous monitoring systems which use calibration gas cells or filters, use three certified calibration gas cells or filters as specified below:

5.3.1 High-Level Gas Cell or Filter. One that produces an output equivalent to 80 to 90 percent of the span value.

5.3.2 Mid-Level Gas Cell or Filter. One that produces an output equivalent to 45 to 55 percent of the span value.

5.3.3 Zero Gas Cell or Filter. One that produces an output equivalent to zero. Alternatively, an analyzer may produce a zero value check by mechanical means, such as a movable mirror.

5.4 Calibration Gas—Gas Cell or Filter Combination. Combinations of the above may be used.

6. Performance Specification Test Procedures.

6.1 Pretest Preparation.

6.1.1 Calibration Gas Certification. The tester may select one of the following alternatives: (a) The tester may use calibration gases prepared according to the protocol defined in Citation 10.5, i.e. These gases may be used as received without reference method analysis (obtain a statement from the gas cylinder supplier certifying that the calibration gases have been prepared according to the protocol); or (b) the tester may use calibration gases not prepared according to the protocol. In case (b), he must perform triplicate analyses of each calibration gas (mid-level and high-level, only) within 2 weeks prior to the operational test period using the appropriate reference methods. Acceptable procedures are described in Citations 10.6 and 10.7. Record the results on a data sheet (example is shown in Figure 2-3). Each of the individual analytical results must be within 10 percent (or 15 ppm, whichever is greater) of the average; otherwise, discard the entire set and repeat the triplicate analyses. If the average of the triplicate reference method test results is within 5 percent of the calibration gas manufacturer's tag value, use the tag value; otherwise, conduct at least 3 additional reference method test analyses until the results of 6 individual runs (the 3 original plus 3 additional) agree within 10 percent or 15 ppm, whichever is greater, of the average. Then use this average for the cylinder value.

Figure 2-3. Analysis of Calibration Gases[a]

Date_____(Must be within 2 weeks prior to the operational test period)

Reference Method Used_____

Sample Run	Mid-level[b] ppm	High-level[c] ppm
1		
2		
3		
Average		
Maximum % Deviation[d]		

[a] Not necessary if the protocol in Citation 10.5 is used to prepare the gas cylinders.

[b] Average must be 45 to 55 percent of span value.

[c] Average must be 80 to 90 percent of span value.

[d] Must be ≤ + 10 percent of applicable average or 15 ppm, whichever is greater.

6.1.2 Calibration Gas Cell or Filter Certification. Obtain (a) a statement from the manufacturer certifying that the calibration gas cells or filters (zero, mid-level, and high-level) will produce the stated instrument responses for the continuous monitoring system, and (b) a description of the test procedure and equipment used to calibrate the cells or filters. At a minimum, the manufacturer must have calibrated the gas cells or filters against a simulated source of known concentration.

6.2 Conditioning Period. Prepare the monitoring system for operation according to the manufacturer's written instructions. At the outset of the conditioning period, zero and span the system. Use the mid-level calibration gas (or gas cell or filter) to set the span at 50 percent of recorder full-scale. If necessary to determine negative zero drift, offset the scale by 10 percent. (Do not forget to account for this when using the calibration curve.) If a zero offset is not possible or is impractical, a low-level drift may be substituted for the zero drift, by using a low-level (5 to 15 percent of span value) calibration gas (or gas cell or filter). This low-level calibration gas (or gas cell or filter) need not be certified. Operate the continuous monitoring system for an initial 168-hour period in the manner specified by the manufacturer. Except during times of instrument zero, calibration checks, and system backpurges, the continuous monitoring system shall collect and condition the effluent gas sample (if applicable), analyze the sample for the appropriate gas constituents, and produce a permanent record of the system output. Conduct daily zero and mid-level calibration checks and, when drift exceeds the daily operating limits, make adjustments. The data recorder shall reflect these checks and adjustments. Keep a record of any instrument failure during this time. If the conditioning period is interrupted because of source breakdown (record the dates and times of process shutdown), continue the 168-hour period following resumption of source operation. If the conditioning period is interrupted because of monitor failure, restart the 168-hour conditioning period when the monitor becomes functional.

6.3 Operational Test Period. Operate the continuous monitoring system for an additional 168-hour period. The continuous monitoring system shall monitor the effluent, except during periods when the system calibration and response time are checked or during system backpurges; however, the system shall produce a permanent record of all operations. Record any system failure during this time on the data recorder output sheet.

It is not necessary that the 168-hour operational test period immediately follow the 168-hour conditioning period. During the operational test period, perform the following test procedures:

6.3.1 Calibration Error Determination. Make a total of 15 nonconsecutive zero, mid-level, and high-level measurements (e g., zero, mid-level, zero, high-level, mid-range, etc.).

This will result in a set of 5 each of zero, mid-level, and high-level measurements. Convert the data output to concentration units, if necessary, and record the results on a data sheet (example is shown in Figure 2–4). Calculate the differences between the reference calibration gas concentrations and the measurement system reading. Then calculate the mean, confidence interval, and calibration errors separately for the mid-level and high-level concentrations using Equations 2–1, 2–2, and 2–3. In Equation 2–3, use each respective calibration gas concentration for R.V.

Figure 2-4. Calibration Error Determination

Run no.	Calibration gas concentration[a] ppm	Measurement system reading ppm	Arithmetic differences ppm	
	A	B	A-B	
			Mid	High
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
Arithmetic Mean (Eq. 2-1) =				
Confidence Interval (Eq. 2-2) =				
Calibration Error (Eq. 2-3)[b] =				

[a] Calibration Data from Section 6.1.1 or 6.1.2

Mid-level: C = _____ppm

High-level: D = _____ppm

[b] Use C or D as R.V. in Eq. 2-3

Figure 2-5. Response Time

Date_____ High-level = _____ ppm

Test Run	Upscale min.	Downscale min.
1		
2		
3		
Average	A =	B =

System Response Time (slower of A and B) = _____ min.

6.3.2 Response Time Test Procedure. At a minimum, each response time test shall provide a check of the entire sample transport line (if applicable), any sample conditioning equipment (if applicable), the pollutant analyzer, and the data recorder. For in-situ systems, perform the response time check by introducing the calibration gases at the sample interface (if applicable), or by introducing the calibration gas cells or filters at an appropriate location in the pollutant analyzer. For extractive monitors, introduce the calibration gas at the sample probe inlet in the stack or at the point of connection between the rigid sample probe and the sample transport line. If an extractive analyzer is used to monitor the effluent from more than one source, perform the response time test for each sample interface.

To begin the response time test, introduce zero gas (or zero cell or filter) into the continuous monitor. When the system output has stabilized, switch to monitor the stack effluent and wait until a "stable value" has been reached. Record the upscale response time. Then, introduce the high-level calibration gas (or gas cell or filter). Once the system has stabilized at the high-level concentration, switch to monitor the stack effluent and wait until a "stable value" is reached. Record the downscale response time. A "stable value" is equivalent to a change of less than 1 percent of span value for 30 seconds or 5 percent of measured average concentration for 2 minutes. Repeat the entire procedure three times. Record the results of each test on a data sheet (example is shown in Figure 2–5). Determine the means of the upscale and downscale response times using Equation 2–1. Report the slower time as the system response time.

6.3.3 Field Test for Zero Drift and Calibration Drift. Perform the zero and calibration drift tests for each pollutant analyzer and data recorder in the continuous monitoring system.

6.3.3.1 Two-hour Drift. Introduce consecutively zero gas (or zero cell or filter) and high-level calibration gas (or gas cell or filter) at 2-hour intervals until 15 sets (before and after) of data are obtained. Do not make any zero or calibration adjustments during this time unless otherwise prescribed by the manufacturer. Determine and record the amount that the output had drifted from the recorder zero and high-level value on a data sheet (example is shown in Figure 2–6). The 2-hour periods over which the measurements are conducted need not be consecutive, but must not overlap. Calculate the zero and calibration drifts for each set. Then calculate the mean, confidence interval, and zero and calibration drifts (2-hour) using Equations 2–1, 2–2, and 2–3. In Equation 2–3, use the span value for R.V.

6.3.3.2 Twenty-Four Hour Drift. In addition to the 2-hour drift tests, perform a series of seven 24-hour drift tests as follows: At the beginning of each 24-hour period, calibrate the monitor, using mid-level value. Then introduce the high-level calibration gas (or gas cell or filter) to obtain the initial reference value. At the end of the 24-hour period, introduce consecutively zero gas (or gas cell or filter) and high-level calibration gas (or gas cell or filter); do not make any adjustments at this time. Determine and record the amount of drift from the recorder zero and high-level value on a data sheet (example is shown in Figure 2–7). Calculate the zero and calibration drifts for each set. Then calculate the mean, confidence interval, and zero and calibration drifts (24-hour) using Equations 2–1, 2–2, and 2–3. In Equation 2–3, use the span value for R.V.

Data set no.	Date	Time		Zero Rdg		Zero drift	Hi-level Rdg		Span drift	Calib. drift
		Begin	End	Init. A	Fin. B	C=B-A	Init. D	Fin. E	F=E-D	G=F-C
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
Arithmetic Mean (Eq. 2-1)										
Confidence Interval (Eq. 2-2)										
Zero Drift[a]							Calibration drift[a]			

[a] Use Equation 2-3, with span value for R. V.

Figure 2-6. Zero and Calibration Drift (2 hour)

Data set no.	Date	Time		Zero Init. A	Rdg Fin. B	Zero drift C=B-A	Hi-level Rdg Init. D	Hi-level Rdg Fin. E	Span drift F=E-D	Calib. drift G=F-C
		Begin	End							
1										
2										
3										
4										
5										
6										
7										
Arithmetic Mean (Eq. 2-1)										
Confidence Interval (Eq. 2-2)										
Zero drift							Calibration drift[a]			

[a] Use Equation 2-3, with the span value for R. V.

Figure 2-7. Zero and Calibration Drift (24-hour)

Note.—Automatic zero and calibration adjustments made by the monitoring system without operator intervention or initiation are allowable at any time. Manual adjustments, however, are allowable only at 24-hour intervals, unless a shorter time is specified by the manufacturer.

6.4 System Relative Accuracy. Unless otherwise specified in an applicable subpart of the regulations, the reference methods for SO_2, NO_x, diluent (O_2 or CO_2), and moisture are Reference Methods 6, 7, 3, and 4, respectively. Moisture may be determined along with SO_2 using Method 6. See Citation 10.8. Reference Method 4 is necessary only if moisture content is needed to enable comparison between the Reference Method and monitor values. Perform the accuracy test using the following guidelines:

6.4.1 Location of Pollutant Reference Method Sample Points. The following specifies the location of the Reference Method sample points which are on the same cross-sectional plane as the monitor's. However, any cross-sectional plane within 2 equivalent diameter of straight runs may be used, by using the projected image of the monitor on the selected plane in the following criteria.

6.4.1.1 For point monitors, locate the Reference Method sample point no further than 30 cm (or 5 percent of the equivalent diameter of the cross section, whichever is less) from the pollutant monitor sample point.

6.4.1.2 For multipoint monitors, locate each Reference Method sample traverse point no further than 30 cm (or 5 percent of the equivalent diameter of the cross section, whichever is less) from each corresponding pollutant monitor sample point.

6.4.1.3 For limited-path and path monitors, locate 3 sample points on a line parallel to the monitor path and no further than 30 cm (or 5 percent of the equivalent diameter of the cross section, whichever is less) from the centerline of the monitor path. The three points of the Reference Method shall correspond to points in the monitor path at 16.7, 50.0, and 83.3 percent of the effective length of the monitor path.

6.4.2 Location of Diluent and Moisture Reference Method Sample Points.

6.4.2.1 For sources which require diluent monitors in addition to pollutant monitors, locate each of the sample points for the diluent Reference Method measurements within 3 cm of the corresponding pollutant Reference Method sample point as defined in Sections 6.4.1.1, 6.4.1.2, or 6.4.1.3. In addition, locate each pair of diluent and pollutant Reference Method sample points no further than 30 cm (or 5 percent of the equivalent diameter of the cross section, whichever is less) from *both* the diluent and pollutant continuous monitor sample points or paths.

6.4.2.2 If it is necessary to convert pollutant and/or diluent monitor concentrations to a dry basis for comparison with the Reference data, locate each moisture Reference Method sample point within 3 cm of the corresponding pollutant or diluent Reference Method sample point as defined in Sections 6.4.1.1, 6.4.1.2, 6.4.1.3, or 6.4.2.1.

6.4.3 Number of Reference Method Tests.

6.4.3.1 For NO_x monitors, make a minimum of 27 NO_x Reference Method measurements, divided into 9 sets.

6.4.3.2 For SO_2 monitors, make a minimum of 9 SO_2 Reference Method tests.

6.4.3.3 For diluent monitors, perform one diluent Reference Method test for each SO_2 and/or NO_x Reference Method test(s).

6.4.3.4 For moisture determinations, perform one moisture Reference Method test for each or each set of pollutant(s) and diluent (if applicable) Reference Method tests.

Note.—The tester may choose to perform more than 9 sets of NO_x measurements or more than 9 SO_2 reference method diluent, or moisture tests. If this option is chosen, the tester may, at his discretion, reject up to 3 of the set or test results, so long as the total number of set or test results used to determine the relative accuracy is greater than or equal to 9. Report all data including rejected data.

6.4.4 Sampling Strategy for Reference Method Tests. Schedule the Reference Method tests so that they will not be in progress when zero drift, calibration drift, and response time data are being taken. Within any 1-hour period, conduct the following tests: (a) one set, consisting of 3 individual measurements, of NO_x and/or one SO_2; (b) one diluent, if applicable; and (c) one moisture (if needed). Whenever two or more reference tests (pollutant, diluent, and moisture) are conducted, the tester may choose to run all these reference tests within a 1-hour period. However, it is recommended that the tests be run concurrently or consecutively within a 4-minute interval if two reference tests employ grab sampling techniques. Also whenever an integrated reference test is run together with grab sample reference tests, it is recommended that the integrated sample be started one-sixth the test period before the first grab sample is collected.

In order to properly correlate the continuous monitoring system and Reference Method data, mark the beginning and end of each Reference Method test period (including the exact time of day) on the pollutant and diluent (if applicable) chart recordings. Use one of the following strategies for the Reference Method tests:

6.4.4.1 Single Point Monitors. For single point sampling, the tester may: (a) take a 21-minute integrated sample (e.g. Method 6, Method 4, or the integrated bag sample technique of Method 3); (b) take 3 grab samples (e.g. Method 7 or the grab sample technique of Method 3), equally spaced at 7-minute (±2 min) intervals (or one-third the test period); or (c) take 3 grab samples over a 3-minute test period.

6.4.4.2 Multipoint or Path Monitors. For multipoint sampling, the tester may either: (a) make a 21-minute integrated sample traverse, sampling for 7 minutes (±2 min) (or one-third the test period) at each point; or (b) take grab samples at each traverse point, scheduling the grab samples to that they are an equal interval (7±2 minutes) of time apart (or one-third the test period).

Note.—If the number of sample points is greater than 3, make appropriate adjustments to the individual sampling time intervals. At times NSPS performance test data may be used as part of the data base of the continuous monitoring relative accuracy tests. In these cases, other test periods as specified in the applicable subparts of the regulations may be used.

6.4.5 Correlation of Reference Method and Continuous Monitoring System Data. Correlate the continuous monitoring system data with the Reference Method test data, as to the time and duration of the Reference Method tests. To accomplish this, first determine from the continuous monitoring system chart recordings, the integrated average pollutant and diluent (if applicable) concentration(s) for each Reference Method test period. Be sure to consider system response time. Then, compare each integrated average concentration against the corresponding average concentration obtained by the Reference Method, use the following guidelines to make these comparisons:

6.4.5.1 If the Reference Method is an integrated sampling technique (e.g., Method 6), make a direct comparison of the Reference Method results and the continuous monitoring system integrated average concentration.

6.4.5.2 If the Reference Method is a grab-sampling technique (e.g., Method 7), first average the results from all grab-samples taken during the test period, and then compare this average value against the integrated value obtained from the continuous monitoring system chart recording.

6.5 Data Summary for Relative Accuracy Tests. Summarize the results on a data sheet; example is shown in figure 2-8. Calculate the arithmetic differences between the reference method and the continuous monitoring output sets. Then calculate the mean, confidence interval, and system relative accuracy, using Equation 2-1, 2-2, and 2-3. In Equation 2-3, use the average of the reference method test results for R.V.

7. Equations

7.1 Arithmetic Mean. Calculate the mean of a data set as follows:

$$\bar{x} = \frac{1}{n} \sum_{i=1}^{n} x_i \qquad \text{Equation 1-2}$$

Where:

x = arithmetic mean.
n = number of data points.
Σx_i = algebraic sum of the individual values, x_i.

When the mean of the differences of pairs of data is calculated, be sure to correct the data for moisture.

7.2 Confidence Interval. Calculate the 95 percent confidence interval (two-sided) as follows:

$$C.I._{95} = \frac{t_{.975}}{n\sqrt{n-1}} \sqrt{n\Sigma x_i^2 - (\Sigma x_i)^2} \qquad \text{Equation 1-3}$$

Where:

$C.I._{95}$ = 95 percent confidence interval estimate of mean value.
$t_{.975} = t_{(1-\alpha/2)}$ (see Table 2-2)

BILLING CODE 6560-01-M

Table 2-2.—*t* = *Values*

n*	$t_{.975}$	n*	$t_{.975}$	n*	$t_{.975}$
2	12 706	7	2 447	12	2 201
3	4 303	8	2 365	13	2 179
4	3 182	9	2 306	14	2 160
5	2 776	10	2 262	15	2 145
6	2 571	11	2 228	16	2 131

* The values in this table are already corrected for n-1 degrees of freedom. Use *n* equal to the number of individual values.

Run no.	Date and time	SO_2 ppm RM	SO_2 ppm M[d]	SO_2 ppm Diff	NO_x[b] ppm RM	NO_x[b] ppm M[d]	NO_x[b] ppm Diff	CO_2 or O_2[a] % RM[d]	CO_2 or O_2[a] % M[d]	SO_2[a] mass/GCV RM	SO_2[a] mass/GCV M	SO_2[a] mass/GCV Diff	NO_x[a] mass/GCV RM	NO_x[a] mass/GCV M	NO_x[a] mass/GCV Diff
1															
2															
3															
4															
5															
6															
7															
8															
9															
10															
11															
12															
Average															
Confidence Interval															
Accuracy[c]															

[a] For steam generators [b] Average of 3 samples [c] Use average of reference method test results for R.V.
[d] Make sure that RM and M data are on a consistent basis, either wet or dry

Figure 2-8. Relative accuracy determination

7.3 Relative Accuracy. Calculate the relative accuracy of a set of data as follows:

$$R.A. = \frac{|\bar{x}|+|C.I._{95}|}{R.V.} \times 100 \quad \text{Equation 2-3}$$

Where: R. A. = relative accuracy

$|\bar{x}|$ = absolute value of the arithmetic mean (from Equation 2-1).

$|C.I._{95}|$ = absolute value of the 95 percent confidence interval (from Equation 2-2).

R.V. = reference value, as defined in Sections 6.3.1, 6.3.3.1, 6.3.3.2, and 6.5.

8. Reporting

At a minimum (check with regional offices for additional requirements, if any) summarize the following results in tabular form: calibration error for mid-level and high-level concentrations, the slower of the upscale and downscale response times, the 2-hour and 24-hour zero and calibration drifts, and the system relative accuracy. In addition, provide, for the conditioning and operational test periods, a statement to the effect that the continuous monitoring system operated continuously for a minimum of 168 hours each, except during times of instrument zero, calibration checks, system backpurges, and source breakdown, and that no corrective maintenance, repair, replacement, or adjustment other than that clearly specified as routine and required in the operation and maintenance manuals were made. Also include the manufacturer's certification statement (if applicable) for the calibration gas, gas cells, or filters. Include all data sheets and calculations and charts (data outputs), which are necessary to substantiate that the system met the performance specifications.

9. Retest

If the continuous monitoring system operates within the specified performance parameters of Table 2-1, the operational test period will be successfully concluded. If the continuous monitoring system fails to meet any of the specifications, repeat that portion of the testing which is related to the failed specification.

10. Bibliography

10.1 "Monitoring Instrumentation for the Measurement of Sulfur Dioxide in Stationary Source Emissions," Environmental Protection Agency, Research Triangle Park, N.C., February 1973.

10.2 "Instrumentation for the Determination of Nitrogen Oxides Content of Stationary Source Emissions," Environmental Protection Agency, Research Triangle Park, N.C., Volume 1, APTD-0847, October 1971; Volume 2, APTD-0942, January 1972.

10.3 "Experimental Statistics," Department of Commerce, Handbook 91, 1963, pp. 3-31, paragraphs 3-3.1.4.

10.4 "Performance Specifications for Stationary-Source Monitoring Systems for Gases and Visible Emissions," Environmental Protection Agency, Research Triangle Park, N.C., EPA-650/2-74-013, January 1974.

10.5 Traceability Protocol for Establishing True Concentrations of Gases Used for Calibration and Audits of Continuous Source Emission Monitors (Protocol No. 1). June 15, 1978. Environmental Monitoring and Support Laboratory; Office of Research and Development, U.S. EPA, Research Triangle Park, N.C. 27711.

10.6 Westlin, P. R. and J. W. Brown. Methods for Collecting and Analyzing Gas Cylinder Samples. Emission Measurement Branch, Emission Standards and Engineering Division, Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, N.C., July 1978.

10.7 Curtis, Foston. A Method for Analyzing NO_x Cylinder Gases—Specific Ion Electrode Procedure. Emission Measurement Branch, Emission Standards and Engineering Division, Office of Air Quality and Standards, U.S. EPA, Research Triangle Park, N.C., October 1978.

10.8 Stanley, Jon and P. R. Westlin. An Alternative Method for Stack Gas Moisture Determination. Emission Measurement Branch, Emission Standards and Engineering Division, Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, N.C., August 1978.

Performance Specification 3—Specifications and Test Procedures for CO_2 and O_2 Continuous Monitors in Stationary Sources

1. Applicability and Principle

1.1 Applicability. This Specification contains (a) installation requirements, (b) instrument performance and equipment specifications, and (c) test procedures and data reduction procedures for evaluating the acceptability of continuous CO_2 and O_2 monitors that are used as diluent monitors. The test procedures are primarily designed for systems that introduce calibration gases directly into the analyzer; other types of monitors (e.g., single-pass monitors, as described in Section 2.2.7 of Performance Specification 2 of this Appendix) will be evaluated on a case-by-case basis upon written request to the Administrator, and alternative procedures will be issued separately.

1.2 Principle. Any CO_2 or O_2 continuous monitor, which is expected to meet this Specification, is operated for a specified length of time. During this specified time period, the continuous monitor is evaluated to determine conformance with the Specification.

2. Definitions

The definitions are the same as those listed in Section 2 of Performance Specification 2.

3. Installation Specifications

3.1 Measurement Location and Measurement Points or Paths. Select and install the continuous monitor at the same sampling location used for the pollutant monitor(s). Locate the measurement points or paths as shown in Figure 3-1 or 3-2.

3.2 Alternative Measurement Location and Measurement Points or Paths The diluent monitor may be

installed at a different location from that of the pollutant monitor, provided that the diluent gas concentrations at both locations differ by no more than 5 percent from that of the pollutant monitor location for CO_2 or the quantity, 20.9-percent O_2, for O_2. See Section 3.4 of Performance Specification 2 for the demonstration procedure.

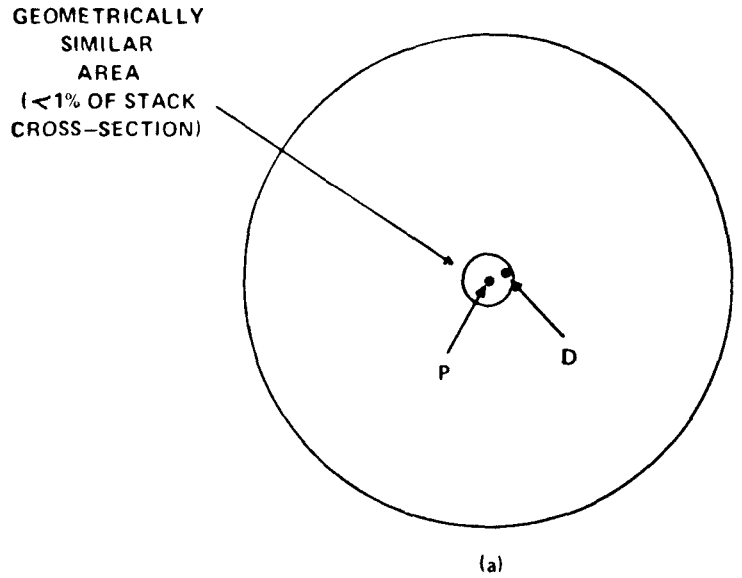
4. Continuous Monitor Performance and Equipment Specifications

The continuous monitor performance and equipment specifications are listed in Table 3–1. To be considered acceptable, the continuous monitor must demonstrate compliance with these specifications, using the test procedures in Section 6.

5. Apparatus

5.1 CO_2 or O_2 Continuous Monitor. Use any continuous monitor, which is expected to meet this Specification. The data recorder may either be an analog strip-chart recorder or other suitable device having an input voltage range compatible with the analyzer output.

5.2 Calibration Gases. Diluent gases shall be air or N_2 for CO_2 mixtures, and shall be N_2 for O_2 mixtures. Use three calibration gases as specified below:



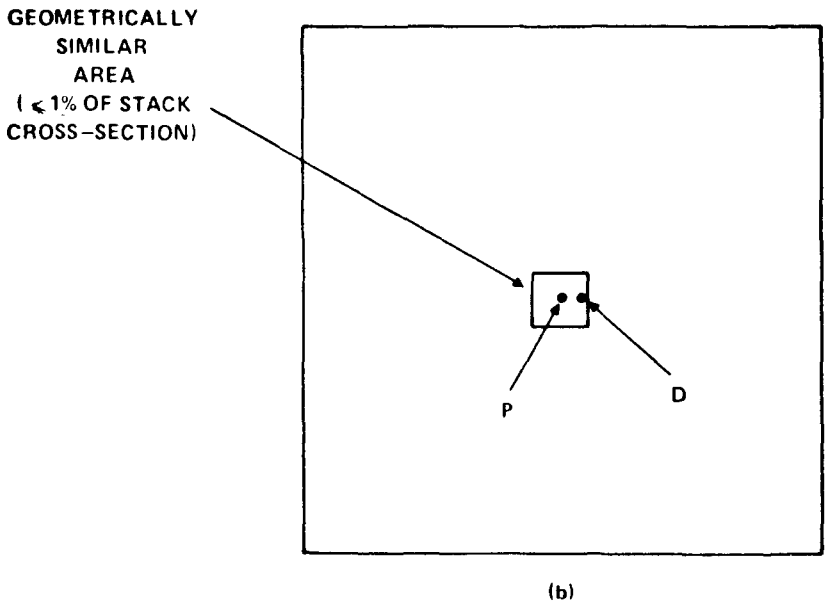


Figure 3-1. Relative locations of pollutant (P) and diluent (D) measurement points in (a) circular and (b) rectangular ducts. P is located at the centroid of the geometrically similar area. Note: The geometrically similar area need not be concentric.

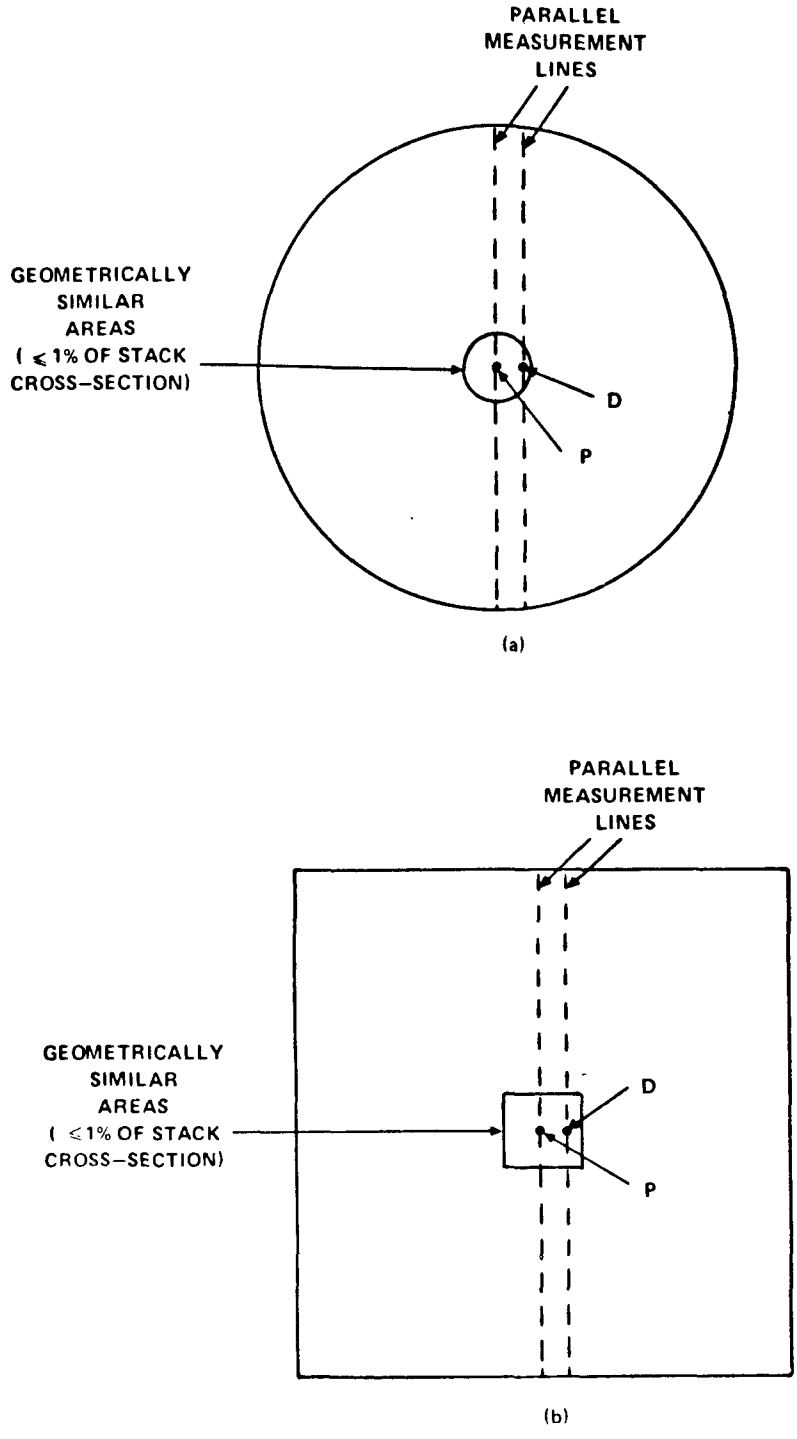


Figure 3-2. Relative locations of pollutant (P) and diluent (D) measurement paths for (a) circular and (b) rectangular ducts. P is located at the centroid of both the geometrically similar areas and the pollutant monitor path cross-sectional areas. D is located at the centroid of the diluent monitor path cross-sectional area.

Table 3-1.—*Performance and Equipment Specifications*

Parameter	Specification
1 Conditioning period [a]	≥ 168 hours
2 Operational test period [a].	≥ 168 hours
3. Calibration error [b] ...	≤ 5 pct. of each (mid-range and high-range, only) calibration gas value
4 Reponse time	≤ 15 minutes
5 Zero drift (2-hour) [b] [c]	≤ 0 4 pct. CO_2 or O_2
6 Zero drift (24-hour) [b] [c].	≤ 10 5 pct. CO_2 or O_2
7 Calibration drift (2-hour) [b].	≤ 0 4 pct. CO_2 or O_2
8 Calibration drift (24-hour) [b].	≤ 0 5 pct. CO_2 or O_2
9 Data recorder chart resolution	Chart scales must be readable to within ≤ 0 50 pct of full-scale
10 Extractive monitors	Must use the same interface as the pollutant monitor Place in a series (diluent after pollutant analyzer) or use a "T"

[a] During the conditioning and operational test periods, the continuous monitor shall not require any corrective maintenance, repair, replacement, or adjustment other than that clearly specified as routine and required in the operation and maintenance manuals.

[b] Expressed as the sum of the absolute mean value plus the 95 percent confidence interval of a series of tests

[c] A low-level (5–15 percent of span value) drift tests may be substituted for the zero drift tests

5.2.1 High-Level Gas. A CO_2 or O_2 concentration of 20.0 to 22.5 percent. For O_2 analyzers, ambient air (20.9 percent O_2) may be used as the high-range calibration gas; lower high-level O_2 concentration may be used, subject to the approval of the Administrator.

5.2.2 Mid-Level Gas. A CO_2 or O_2 concentration of 11.0 to 14.0 percent; for O_2 analyzers, concentrations in the operational range may be used.

5.2.3 Zero Gas. A CO_2 or O_2 concentration of less than 0.05 percent. For CO_2 monitors, ambient air (0.03 percent CO_2) may be used as the zero gas.

6. Performance Specification Test Procedures.

6.1 Calibration Gas Certification. Follow the procedure as outlined in Section 6.1.2 of Performance Specification 2, except use 0.5 percent CO_2 or O_2 instead of the 15 ppm. Figure 3–3 is provided as an example data sheet.

6.2 Conditioning Period. Follow the same procedure outlined in Section 6.2 of Performance Specification 2.

6.3 Operational Test Period. Follow the same procedures outlined in Section 6.3 of Performance Specification 2, to evaluate the calibration error, response time, and the 2-hour and 24-hour zero and calibration drifts. See example data sheets (Figures 3–4 through 3–7).

6.4 System Relative Accuracy. (Note: The relative accuracy is not determined separately for the diluent monitor, but is determined for the pollutant-diluent system.) Unless otherwise specified in an applicable subpart of the regulations, the Reference Methods for the diluent concentration determination shall be Reference Method 3 for CO_2 or O_2. For this test, Fyrite analyses may be used for CO_2 and O_2 determinations. Perform the measurements using the guidelines below (an example data sheet is shown in Figure 2–8 of Performance Specification 2):

6.4.1 Location of Reference Method 3 Sampling Points. Locate the diluent Reference Method sampling points according to the guidelines given in Section 6.4.2.1 of Performance Specification 2.

6.4.2 Number of Reference Method Tests. Perform one Reference Method 3 test according to the guideline in Performance Specification 2.

6.4.3 Sampling Strategy for Reference Method Tests. Use the basic Reference Method sampling strategy outlined in Section 6.4.4 (and related sub-sections) of Performance Specification 2.

6.4.4 Correlation of Reference Method and Continuous Monitor Data. Use the guidelines given in Section 6.4.5 of Performance Specification 2.

7. Equations, Reporting, Retest, and Bibliography. The procedure and citations are the same as in Sections 7 through 10 of Performance Specification 2.

[FR Doc 79-31033 Filed 10-9-79 8 45 am]

Figure 3-3. Analysis of Calibration Gases[a]

Date_____(Must be within 2 weeks prior to the operational test period)

Reference Method Used_____

Sample run	Mid-range[c] ppm	High-range[d] ppm
1		
2		
3		
Average		
Maximum % deviation[e]		

[a] Not necessary if the protocol in Citation 10.5 of Performance Specification 2 is used to prepare the gas cylinders.

[c] Average must be 11.0 to 14.0 percent; for O_2, see Section 5.2.2.

[d] Average must be 20.0 to 22.5 percent; for O_2, see Section 5.2.1.

[e] Must be $\leq \pm$ 10 percent of applicable average or 0.5 percent, whichever is greater.

Figure 3-4. Calibration Error Determination

Run No.	Calibration Gas Concentration[a] ppm	Measurement System Reading ppm	Arithmetic Differences ppm	
	A	B	A-B	
			Mid	High
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
Arithmetic Mean (Eq. 2-1)[b] =				
Confidence Interval (Eq. 2-2)[b] =				
Calibration Error (Eq. 2-3)[b,c] =				

[a] Calibration Data from Section 6.1

Mid-level: C = _____ ppm

High-level: D = _____ ppm

[b] See Performance Specification 2

[c] Use C or D as R. V.

Figure 3-5. Response Time

Date _____ High-Range = _____ ppm

Test Run	Upscale min	Downscale min
1		
2		
3		
Average	A =	B =

System Response Time (slower of A and B) = _____ min.

Data set no	Date	Time		Zero Rd.		Zero drift	Hi-Range Rdg.		Span drift	Calib. drift
		Begin	End	Init.	Fin.		Init.	Fin.		
				A	B	C=B-A	D	E	F=E-D	G=F-C
Arithmetic Mean (Eq. 2-1)[a]										
Confidence Interval (Eq. 2-2)[a]										
Zero drift[b]							Calibration drift[b]			

[a] From Performance Specification 2.

[b] Use Equation 2-3 of Performance Specification 2 and 1.0 for R. V.

Figure 3-6. Zero and Calibration Drift (2 hour)

Data set no.	Date	Time		Zero Rdg		Zero drift	Hi-Range Rdg		Span drift	Calib. drift
		Begin	End	Init.	Fin.		Init.	Fin.		
				A	B	C=B-A	D	E	F=E-D	G=F-C
Arithmetic Mean (Eq. 2-1)[a]										
Confidence Interval (Eq. 2-2)[a]										
Zero drift [b]							Calibration drift [b]			

[a] From Performance Specification 2.

[b] Use Equation 2-3 of Performance Specification 2, with 1.0 for R. V.

Figure 3-7. Zero and Calibration Drift (24-hour)

40 CFR Part 60

[FRL 1378-3]

Standards of Performance for New Stationary Sources Continuous Monitoring Performance Specifications; Extension of Comment Period

AGENCY: Environmental Protection Agency (EPA).

ACTION: Extension of Comment Period.

SUMMARY: The deadline for submittal of comment on the proposed revisions to the continuous monitoring performance specifications, which were proposed on October 10, 1979 (44 FR 58602), is being extended from December 10, 1979, to February 11, 1980.

DATES: Written comments and information must be received on or before February 11, 1980.

ADDRESSES: *Comments.* Written comments and information should be submitted (in duplicate, if possible) to: Central Docket Section (A-130), Attention: Docket Number OAQPS-79-4, U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460.

Docket. Docket Number OAQPS-79-4, containing material relevant to this rulemaking, is located in the U.S. Environmental Protection Agency Central Docket Section, Room 2903B, 401 M Street, S.W., Washington, D.C. 20460. The docket may be inspected between 8:00 a.m. and 4:00 p.m. on weekdays, and a reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Don R. Goodwin (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, N.C. 27711; telephone (919) 541-5271.

SUPPLEMENTARY INFORMATION: On October 10, 1979 (44 FR 58602), the Environmental Protection Agency proposed revisions to the Continuous Monitoring Performance Specifications 1, 2, and 3. The notice of proposal requested public comments on the standards by December 10, 1979. Due to delay in the shipping of copies of the performance specifications publication, a sufficient number of copies have been unavailable for distribution to all interested parties in time to allow their meaningful review and comment by December 10, 1979. An extension of this period is justified as this delay has resulted in about a 5-week delay in processing requests for the document.

Dated: December 12, 1979.

Edward F. Tuerk,

Acting Assistant Administrator for Air, Noise, and Radiation.

[FR Doc 79-39062 Filed 12-19-79, 8:45 am]

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1389-2]

Standards of Performance for New Stationary Sources Continuous Monitoring Performance Specifications

AGENCY: Environmental Protection Agency (EPA).

ACTION: Advance notice of proposed rulemaking.

SUMMARY: This notice sets forth draft Performance Specification 4—Specifications and Test Procedures for Carbon Monoxide Continuous Monitoring Systems in Stationary Sources, which EPA is considering to propose as an addition to Appendix B of 40 CFR Part 60. The intent of this advance notice is to solicit comments on the specifications and testing procedures EPA is considering

This advance notice of proposed rulemaking is issued under the authority of Sections 111, 114, and 301(a) of the Clean Air Act as amended (42 U.S.C 7411, 7414, and 7601(a)).

DATES: Written comments and information should be post-marked on or before May 20, 1980.

ADDRESSES: *Comments.* Written comments and information should be submitted (in duplicate, if possible) to: Central Docket Section (A-130), Attention: Docket Number A-79-03, U.S. Environmental Protection Agency, 401 M Street, SW., Washington, D.C. 20460

Docket. Docket Number A-79-03, containing material relevant to this rulemaking, is located in the U.S. Environmental Protection Agency Central Docket Section, Room 2903B, 401 M Street, SW., Washington, D.C. 20460 The docket may be inspected between 8:00 a.m. and 4:00 p.m. on weekdays, and a reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Don Goodwin (MD-13), U.S Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone (919) 541-5271.

SUPPLEMENTARY INFORMATION: EPA promulgated standards of performance for new stationary sources pursuant to Section 111 of the Clean Air Act, as amended, on March 8, 1974 (39 FR 9308) for petroleum refineries and six other stationary sources. New or modified sources in these categories are required to demonstrate compliance with the standards of performance by means of performance tests that are conducted at the time a new source commences operation or shortly thereafter. To ensure that these sources are properly operated and maintained so as to remain in compliance, provisions were included in the standards that require sources to install and operate a continuous emission monitoring system. One such requirement was for carbon monoxide (CO) from petroleum refineries.

When the standards were initially proposed, EPA had limited knowledge about the operation of continuous monitors on such sources; thus, the continuous emission monitoring requirements were specified in general terms. Additional guidance on the selection and use of such instruments was to be provided at a later date.

On October 6, 1975 (40 FR 46259), the Environmental Protection Agency amended Part 60 of the regulations by adding Appendix B—Performance Specifications 1, 2, and 3 for continuous monitoring of (1) opacity, (2) sulfur dioxide and nitrogen oxide, and (3) oxygen or carbon dioxide, respectively Performance specifications for CO monitors were not published at that time.

EPA has conducted short-term evaluations of the applicability of several continuous monitoring instruments and has published the results in the following documents: *Guidelines for Development of a Quality Assurance program: Volume VIII—Determination of CO Emissions from Stationary Sources by NDIR Spectrometry*, EPA-650/4-74-005-h (February 1975); and *Evaluation of Continuous Monitors for Carbon Monoxide in Stationary Sources*, EPA-600/2-77-063) March 1977). Both are available through the National Technical Information Service, Springfield, Virginia 22161.

Based on the above documents, specifications and test procedures were drafted for continuous CO monitoring instruments. the format of the draft Performance Specification 4 follows closely that of the most recent proposed revisions to Performance Specification 2 (44 FR 58602 dated Oct. 10, 1979). Several references are made in Performance Specification 4 to specific sections of the Performance Specification 2 revisions.

The Environmental Monitoring and Support Laboratory of EPA is also presently conducting a laboratory and long-term field study of CO continuous monitoring systems. Results of this study will provide essential background and technical information in support of or improvement to Performance Specification 4. The completion date is scheduled for mid-1981. For this reason, Performance Specification 4 for CO is published as an advance notice.

Specific Requests

EPA is requesting comments on the attached draft Performance Specification 4—Specifications and Test Procedures for CO Monitoring Systems in Stationary Sources. EPA is interested in comments on alternatives to the performance specifications and is particularly interested in information that could lead to the development of improved or alternative procedures. EPA is also interested in comments on the following aspects of CO continuous monitoring and Performance Specification 4: (1) Estimates of installation and operation costs including equipment costs, manpower requirements, data reduction options, and maintenance costs, (2) procedures applicable for the evaluation of single-pass, in-situ monitoring system; (3) laboratory testing procedures that are necessary for determining monitoring system performance acceptability and those laboratory tests that can be recommended as indications of the quality of equipment operation; (4) the specifications and limits set forth in Section 4; (5) the applicability of Reference Method 10 or other methods for determining relative accuracy of continuous CO monitoring systems

Dated: February 12, 1980.

Barbara Blum,

Acting Administrator.

Performance Specification 4—Specifications and Test Procedures for Carbon Monoxide Continuous Monitoring Systems in Stationary Sources

1. Applicability and Principle

1.1 Applicability. This specification contains (a) installation requirements, (b) instrument performance and equipment specifications, and (c) test procedures and data reduction procedures for evaluating the acceptability of carbon monoxide (CO) continuous monitoring systems. The test procedures are not applicable to single-pass, in-situ monitoring systems; these systems will be evaluated on a case-by-case basis upon application to the Administrator, and alternative procedures will be issued separately

1.2 Principle. A CO continuous monitoring system that is expected to meet this specification is installed, calibrated, and operated for a specified length of time. During the specified time period, the continuous monitoring

system is evaluated to determine conformance with the specification.

2. Definitions

The definitions are the same as those listed in Section 2 of Performance Specification 2.

3. Installation Specifications

Install the continuous monitoring system at a location where the pollutant concentration measurements are representative of the total emissions from the affected facility. Use a point, points, or a path that represents the average concentration over the cross section. Both requirements can be met as follows:

3.1 Measurement Location. Select an accessible measurement location in the stack or ductwork that is at least two (2) equivalent diameters downstream from the nearest CO control device or other point at which a change in the pollutant concentration may occur and at least 0.5 equivalent diameter upstream from the exhaust. Individual subparts of the regulations may contain additional requirements.

3.2 Measurement Points or Paths. The tester may choose to use the following measurement point, points, or path without a stratification check or he may choose to conduct the stratification check procedure given in Section 3.3 of Performance Specification 2 to select the point, points, or path of average gas concentration.

3.2.1 CO Path Monitoring Systems. Same as in Performance Specification 2, Section 3.2.2.

3.2.3 Single-Point and Limited-Path Monitoring Systems. Same as in Performance Specification 2, Section 3.2.3.

4. Performance and Equipment Specifications

The continuous monitoring system performance and equipment specifications are listed in Table 4–1. To be considered acceptable, the continuous monitoring system must demonstrate compliance with these specifications using the test procedures of Section 6.

5. Apparatus

5.1 Continuous Monitoring System. Use any continuous monitoring system for CO, which is expected to meet the specifications in Table 4–1. The data recorder may be an analog strip-chart recorder or other suitable device with an input signal range compatible with the analyzer output.

Table 4-1.—*Continuous Monitoring System Performance and Equipment Specifications*

Parameter	Specification
1 Conditioning period [a] ..	≥ 168 hours.
2 Operational test period [a].	≥ 168 hours.
3. Calibration error [b]	≤ 5 percent of each mid-level and high-level calibration value
4 Response time	≤ 10 minutes.
5 Zero drift, 2 hours [a]	≤ 1 percent of span value.
6 Zero drift, 24 hours [a]	≤ 2 percent of span value
7 Calibration drift, 2 hours [a]	≤ 2 percent of span value.
8 Calibration drift, 24 hours [a]	≤ 2 5 percent of span value.
9 Relative accuracy [a]	≤ 10 percent of Mean Ref value.
10 Calibration gas cells or filters.	Must provide a check of all analyzer internal mirrors and lenses, and all electronic circuitry including the radiation source and detector assembly, which are normally used in sampling and analysis.
11 Data recorder chart resolution.	Chart scales must be readable to within ± 0.5 percent of full-scale

[a] During the conditioning and operational test periods, the continuous monitoring system shall not require any corrective maintenance, replacement, or adjustment other than that clearly specified as routine and required in the operation and maintenance manuals

[b] Expressed as sum of absolute mean value plus 95 percent confidence interval of a series tests divided by a reference value

5.2 Calibration Gases. For continuous monitoring systems that allow the introduction of calibration gases to the analyzer, the calibration gases must be CO in N_2. Use three calibration gas mixtures as specified below;

5.2.1 High-Level Gas. A gas concentration that is equivalent to 80 to 90 percent of the span value.

5.2.2 Mid-Level Gas. A gas concentration that is equivalent to 45 to 55 percent of the span value.

5.2.3 Zero Gas. A gas concentration of less than 0.25 percent of the span value. Prepurified nitrogen should be used.

5.3 Calibration Gas Cells or Filters. For continuous monitoring systems which use calibration gas cells or filters, use three certified calibration gas cells or filters as specified below:

5.3.1 High-Level Gas Cell or Filter. One that produces an output equivalent to 80 to 90 percent of the span value.

5.3.2 Mid-Level Gas Cell or Filter. One that produces an output equivalent to 45 to 55 percent of the span value.

5.3.3 Zero Gas Cell or Filter. One that produces an output equivalent to zero. Alternatively, an analyser may produce a zero value check by mechanical means, such as a movable mirror.

6. Performance Specification Test Procedures

6.1 Pretest Preparation.

6.1.1 Calibration Gas Analyses. Use calibration gas prepared according to the protocol defined in Reference 10.2.

6.1.2 Calibration Gas Cell or Filter Certification. Obtain from the manufacturer a statement certifying that the calibration gas cells or filters (zero, mid-level, and high-level) will produce the stated instrument response for the continuous monitoring system, and a description delineating the test procedure and equipment used to calibrate the cells or filters. At a minimum, the manufacturer must have calibrated the gas cells or filters against a simulated source of known concentration.

6.2 Continuous Monitoring System Preparation.

6.2.1 Installation. Install the continuous monitoring system according to the measurement location procedures outlined in Section 3 of this specification. Prepare the system for operation according to the manufacturer's written instructions.

6.2.2 Conditioning Period. Follow the procedure in Performance specification 2, Section 6.2.

6.3 Operational Test Period. Follow the procedure in Performance Specification 2, Section 6.3 and the following subsections:

6.3.1 Calibration Error Determination. Follow the procedures in Performance Specification 2, Section 6.3.1.

6.3.2 Response Time Test Procedure. Follow the procedures in Performance Specification 2, Section 6.3.2.

6.3.3 Field Test for Zero Drift and Calibration Drift. Follow the procedures in Performance specification 2, Section 6.3.3.

6.4 System Relative Accuracy. Follow the procedures in Performance Specification 2, Section 6.4 and all the accompanying subsections. The reference method is Reference Method 10.

6.5 Data Summary for Relative Accuracy Tests. Follow the procedures in Performance Specification 2, Section 6.5.

7. Equations and Reporting

Follow the procedures in Performance Specification 2, Section 7 and all the accompanying subsections.

8. Reporting

Follow the procedures in Performance Specification 2, Section 8.

9. Retest

Follow the procedures in Performance Specification 2, Section 9.

10. *Bibliography*

10.1 Repp, Mark. Evaluation of Continuous Monitors for Carbon Monoxide in Stationary Sources. U.S. Environmental Protection Agency. Research Triangle park, NC. Publication No. EPA–600/2–77–063. March 1977.

10.2 Traceability Protocol for Establishing True Concentrations of Gases Used for Calibration and Audits of Continuous Source Emission Monitors (Protocol No. 1). June 15, 1978. Environmental Monitoring and Support Laboratory, Office of Research Development, U.S. Environmental Protection Agency. Research Triangle Park, NC 27711.

10.3 Department of Commerce. Experimental Statistics. Handbook 91. Library of Congress No. 63–60072. U.S. Government Printing Office, Washington, DC.

[FR Doc 80–5289 Filed 2–19–80; 8:45 am]

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO.	2.	3 RECIPIENT'S ACCESSION NO.
EPA-340/1-80-001a		

4. TITLE AND SUBTITLE	5 REPORT DATE
Standards of Performance for New Stationary Sources - A Compilation as of July 1, 1980	July 1980 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S)	8. PERFORMING ORGANIZATION REPORT NO. PN 3570-3-S
9. PERFORMING ORGANIZATION NAME AND ADDRESS PEDCo Environmental, Inc. 11499 Chester Road Cincinnati, Ohio 45246	10. PROGRAM ELEMENT NO. 11 CONTRACT/GRANT NO. 68-01-4147, Task 136
12. SPONSORING AGENCY NAME AND ADDRESS U.S. Environmental Protection Agency Division of Stationary Source Enforcement Washington, D.C. 20460	13. TYPE OF REPORT AND PERIOD COVERED Supplement, Jan 80 to July 80 14. SPONSORING AGENCY CODE

15. SUPPLEMENTARY NOTES

DSSE Project Officer: Kirk Foster, MD-7, Research Triangle Park, NC 27711; (919) 541-4571

16. ABSTRACT

This document contains those pages necessary to update Standards of Performance for New Stationary Sources - A Compilation, published by the U.S. Environmental Protection Agency, Division of Stationary Source Enforcement in November 1977 (EPA-340/1-77-015) and other supplements published in 1979 and 1980. It is only an update and must be used in conjunction with the original compilation and previous supplements.

Included in this update, with complete instructions for filing are: a title page and table of contents; a new summary table; all revised and new Standards of Performance; the full text of all revisions and standards promulgated since January 1980; and all newly proposed standards or revisions.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution Control Regulations; Enforcement	New Source Performance Standards	13B 14B

18. DISTRIBUTION STATEMENT	19. SECURITY CLASS *(This Report)*	21. NO. OF PAGES
Unlimited	Unclassified	
	20. SECURITY CLASS *(This page)*	22. PRICE
	Unclassified	

EPA Form 2220-1 (9-73)

☆U.S. GOVERNMENT PRINTING OFFICE 1981—735-000/3025 REGION NO. 4