

# **REGULATIONS AND RESOURCE FILE OF CONTINUOUS EMISSION MONITORING INFORMATION**

## **Interim Report**



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

REGULATIONS AND RESOURCE FILE  
OF CONTINUOUS MONITORING INFORMATION

Interim Report

by

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November, 1978

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## INTRODUCTION

On October 6, 1975, EPA promulgated regulations that require specified categories of new and modified stationary sources to continuously monitor their emissions and/or processes. Also on October 6, 1975, EPA promulgated a regulation that requires States to revise their State Implementation Plans to include continuous monitoring requirements for existing sources. As a result of these regulations, much information related to continuous monitoring has developed. This resource file is a compilation and organization of continuous monitoring information. It contains function statements for EPA organizations that work in continuous monitoring, identification of EPA personnel that work in continuous monitoring, identification of vendors of continuous monitoring equipment, regulatory information related to continuous monitoring, and a bibliography of continuous monitoring publications.

The continuous monitoring information was collected by talking with EPA personnel, reading continuous monitoring publications, carefully studying the regulations, and by talking with vendors of continuous monitoring equipment. Janet Zieleniewski, of PEDCo Environmental Specialists, was responsible for compiling updated continuous monitoring regulations.

EPA PERSONNEL AND ORGANIZATIONS  
INVOLVED WITH CONTINUOUS MONITORING

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## Continuous Monitoring Subject Index

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|------------------------------------------|---------------------------|----------------|
| <b>Federal Register Regulations</b>      |                           |                |
| Development                              | Larry Jones - ESED        | 629-5421       |
|                                          | Gene Smith - ESED         | 629-5421       |
| Enforcement                              | Lou Paley - DSSE          | 755-8137       |
| Interpretation                           | Rich Biondi - DSSE        | 755-2564       |
| <b>Standards</b>                         |                           |                |
| Development                              | Larry Jones - ESED        | 629-5421       |
| Field Evaluation                         | George Walsh - ESED       | 629-5423       |
|                                          | Ed McCarley - ESED        | 629-5245       |
| <b>Monitoring Methods</b>                |                           |                |
| Applications, Development & Evaluation   | Roger Shigehara - ESED    | 629-5216       |
| Enforcement Applications                 | Lou Paley - DSSE          | 755-8137       |
| Research, Development, & Evaluations     | John Nader - ESRL         | 629-3085       |
| <b>Enforcement</b>                       |                           |                |
| General Policy                           | John Rasnic - DSSE        | 755-2564       |
| Training Materials & Manuals             | Lou Paley - DSSE          | 755-8137       |
|                                          | Kirk Foster - DSSE        | 629-4571       |
| Determinations of Applicability          | Rich Biondi - DSSE        | 755-2564       |
| <b>Quality Assurance</b>                 |                           |                |
| Implementation of EPA Quality Assurance  | John Clements - EMSL      | 629-2196       |
| Traceability Protocol                    | Darryl Von Lehmden - EMSL | 629-2415       |
| Monitoring Instrumentation Performance   |                           |                |
| Audits                                   | Tom Logan - EMSL          | 629-2580       |
| <b>Continuous Monitoring Research</b>    |                           |                |
| Transmissometry                          | Bill Conner - ESRL        | 629-3173       |
| Gas Monitors                             | Jim Homolya - ESRL        | 629-3085       |
|                                          | Ro Rollins - ESRL         | 629-3171       |
|                                          | Jim Cheney - ESRL         | 629-3172       |
| Transport Systems (extractive analyzers) | Jim Homolya - ESRL        | 629-3085       |

| <u>Subject</u>              | <u>Person-Division</u> | <u>Phone #</u> |
|-----------------------------|------------------------|----------------|
| Remote Gas Sensing          | Bill Herget - ESRL     | 629-3184       |
| Remote Particulate Sensing  | Bill Conner - ESRL     | 629-3173       |
|                             | Jim Vincent - NEIC     | 239-4656       |
| Continuous Process Monitors |                        |                |
| Use of                      | James Dorsey - IERL    | 629-2557       |
|                             | Bill Kuykendall - IERL | 629-2557       |
| State Implementation Plans  |                        |                |
| Revisions                   | Gary Rust - CPDD       | 629-5365       |
|                             | Johnnie Pearson - CPDD | 629-5497       |

## Regional Office Continuous Monitoring Contacts

### Region I

| <u>Person</u> | <u>Division</u> | <u>Phone Number</u> |
|---------------|-----------------|---------------------|
| Marcia Spink  | A&HM            | 223-6883            |
| Jerry Levy    | Enf.            | 223-5610            |

### Region II

|                 |                |          |
|-----------------|----------------|----------|
| Joseph Spatola  | S&A            | 340-6690 |
| Dennis Santella | Air Facilities | 264-9628 |

### Region III

|            |      |          |
|------------|------|----------|
| Gary Gross | Enf. | 597-8907 |
|------------|------|----------|

### Region IV

|               |      |          |
|---------------|------|----------|
| Vince Hellwig | Enf. | 257-4298 |
|---------------|------|----------|

### Region V

|                |      |          |
|----------------|------|----------|
| Dave Kee       | Enf. | 353-2090 |
| Edward Zylstra | S&A  | 353-2303 |

### Region VI

|               |      |          |
|---------------|------|----------|
| Phil Schwindt | S&A  | 749-7126 |
| John Hepola   | Enf. | 749-7675 |

### Region VII

|              |      |          |
|--------------|------|----------|
| Peter Culver | Enf. | 758-2576 |
| John Giar    | S&A  | 758-4461 |

### Region VIII

|            |     |          |
|------------|-----|----------|
| John Floyd | S&A | 327-4261 |
|------------|-----|----------|

Region IX

| <u>Person</u>    | <u>Division</u> | <u>Phone Number</u> |
|------------------|-----------------|---------------------|
| Peter Van Patten | Enf.            | 556-0970            |
| Kent Kitchingman | S&A             | 556-8047            |

Region X

|          |     |          |
|----------|-----|----------|
| Paul Boy | S&A | 399-1106 |
|----------|-----|----------|

## ORGANIZATION FUNCTION STATEMENTS

### I. The Division of Stationary Source Enforcement (DSSE)

The Division of Stationary Source Enforcement provides for the enforcement of continuous emission monitoring regulations by developing and distributing enforcement and regulatory guidelines, developing policies and procedures for surveillance programs, publishing training materials, organizing workshops on monitoring related areas, and providing guidance and assistance to regional offices and State agencies.

DSSE increases the utility and effectiveness of continuous emission monitoring programs by assuring the enforceability of NSPS and NESHAP regulations, suggesting the use of continuous monitors for additional source categories, developing improved procedures for data handling and reporting, interpreting the regulations, and providing regional offices with determinations of applicability.

### II. The Control Programs Development Division (CPDD)

The Control Programs Development Division is responsible for reviewing, evaluating, and reporting on the implementation of air program activities by regional, state, and local agencies; managing training and technical information services; reviewing SIP continuous monitoring revisions; and promulgating national SIP revisions when state revisions are deficient.

### III. The Emission Standards and Engineering Division (ESED)

The Emission Standards and Engineering Division is responsible for developing and revising the NSPS and NESHAP continuous monitoring provisions as needed; specifying continuous monitoring requirements for additional NSPS and NESHAP source categories; developing, evaluating and improving continuous monitoring methods and equipment; conducting continuous monitoring in support of standard development; compiling and maintaining emission test data; and providing guidance to regional offices on matters pertaining to continuous emission monitoring.

IV. The Environmental Monitoring and Support Laboratory, Quality Assurance Branch (EMSL, QAB)

The Environmental Monitoring and Support Laboratory, Quality Assurance Branch is responsible for developing and maintaining quality assurance programs for the EPA. EMSL, QAB is also responsible for providing monitoring methods development, performing continuous monitoring equipment performance audits, and establishing protocol for traceability of calibration gases used with continuous emission monitors.

V. The Industrial Environmental Research Laboratory (IERL)

The Industrial Environmental Research Laboratory develops, evaluates, and applies continuous emission and process monitoring for technology studies of industrial and energy processes.

VI. The Environmental Science Research Laboratory, Stationary Source Research Branch (ESRL, SSRB)

The Environmental Science Research Laboratory, Stationary Source Research Branch conducts research and development studies on continuous monitoring methods and instrumentation for measuring opacity and gaseous and particulate pollutants; develops new measurement methods and instrumentation; evaluates prototype and unproven continuous monitoring instruments; and conducts studies to determine the correlation between opacity measurements and particulate emissions.

## MONITORING REGULATIONS

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## CONTINUOUS EMISSION MONITORING REGULATIONS

The Environmental Protection Agency has promulgated revisions to Parts 51, 60, and 61 of Title 40 of the Code of Federal Regulations to require stationary sources of air pollution to install, operate, and maintain continuous emission monitoring systems.

On October 21, 1976, the Environmental Protection Agency added vinyl chloride to the list of hazardous air pollutants that are regulated by National Emission Standards for Hazardous Air Pollutants, 40 CFR Part 61. Section 61.68 requires new and existing stationary sources to continuously monitor emissions of vinyl chloride. Existing sources and new sources with a startup date preceding the effective date of the regulation are to comply with the regulation within 90 days after the effective date. New sources with a startup date after the effective date are to comply with the regulation within 90 days after startup. The owners or operators are required to report excess emissions to EPA semiannually, on March 15 and September 15.

The EPA, on October 6, 1975, promulgated a regulation that required States to revise, by October 6, 1976, their State Implementation Plans to include legally enforceable procedures requiring certain categories of existing stationary sources to continuously monitor emissions. The States, as a minimum, must require existing stationary sources in the following categories to install, operate, and maintain equipment to continuously

monitor and record emissions: Fossil Fuel Fired Steam Generators, Nitric Acid Plants, Sulfuric Acid Plants, and Petroleum Refineries. The sources shall be required to install monitoring systems that comply with performance specifications and to submit quarterly reports to the State that include the frequency and magnitude of excess emissions and the inoperativeness, repairs, and adjustments of the continuous monitoring systems. The States must require the sources to begin monitoring within 18 months of the SIP approval or EPA promulgation. If the States does not submit SIP revisions or if submitted revisions are inadequate, EPA will promulgate substitute regulations requiring continuous emission monitoring.

Also, on October 6, 1975, the EPA promulgated revisions to New Source Performance Standards (NSPS), 40 CFR Part 60, to require certain specified categories of new and modified stationary sources to install, operate, and maintain equipment to continuously monitor and record emissions. The NSPS regulations require that affected facilities install monitoring systems prior to conducting performance tests of the affected facility as required by 60.8 (unless continuous monitor installation depends upon results of performance test - i.e. NO<sub>x</sub> monitor installation). The source is required to evaluate the performance of each emission monitoring system during the performance test or within 30 days thereafter. The source is required to maintain a file of continuous monitoring measurements and to submit quarterly reports that include frequency and

magnitude of excess emissions and inoperativeness, repairs, and adjustments of the continuous monitoring systems. Continuous monitoring information and requirements are found in three places in Part 60: Subpart A, General Provisions; Subparts D-AA, Subparts for specific source categories; and Appendix B, Performance Specifications.

Currently the primary purpose of NSPS continuous monitoring, with the exception of Primary Lead, Zinc, and Copper Smelters, is to insure that emission control systems are properly operated and maintained and to serve as indicators of emissions. Continuous monitors at primary smelters are used to determine compliance with SO<sub>2</sub> standards. States have the option of revising their SIP so that continuous monitoring is used for insuring proper operation and maintenance of the emission control equipment or for determining compliance with emissions standards.

This compilation of regulatory information contains excerpts from the three Parts (51, 60 and 61) of the Code of Federal Regulations that require stationary sources to continuously monitor emissions and/or processes. This information is compiled to produce a concise package of updated monitoring regulations. It is intended that this is concise for ease of use, but sufficiently inclusive to answer questions and to allow for interpretations of the monitoring regulations. Parts of the preambles, which contain explanations, discussion, and background information, have been included.

Section I contains monitoring regulations that have been extracted from Part 60, NSPS and is divided into the following parts: current continuous monitoring regulations; excerpts of preambles; and presently proposed regulations and proposed revisions to existing regulations.

Section II contains the required SIP revision requirements promulgated by EPA.

Section III contains the monitoring requirements that are included in Part 61, NESHAP.

Following Section III, there are several summary tables of regulatory information that have been abstracted from NSPS, SIP, and NESHAP monitoring requirements. The tables contain information in useful, concise formats. Since the tables are summaries, they do not include all the examples, exceptions, and exemptions that are included in the regulations. One should refer to the text of the regulations to answer any legal questions that arise or to make regulatory interpretations.

**ENVIRONMENTAL  
PROTECTION  
AGENCY**

**STANDARDS OF  
PERFORMANCE FOR NEW  
STATIONARY SOURCES**

## Subpart A—General Provisions

### § 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.

### § 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 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.

(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 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.

(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.

(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 conditions" means a temperature of 20°C (68°F) and a pressure of 760 mm of Hg (29.92 in. of 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.

(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) "One-hour period" means any 60 minute period commencing on the hour.

(s) "Reference method" means any method of sampling and analyzing for an air pollutant as described in Appendix A to this part.

(t) "Equivalent method" means any method of sampling and analyzing for an air pollutant which have been demonstrated to the Administrator'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 Appendix A to this part or an equivalent or alternative method.

(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.

(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 ap-

plicable subparts, used to measure and record (if applicable) process parameters.

(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.

\* \* \* \* \*

### § 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:

\* \* \* \* \*

(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.

\* \* \* \* \*

#### § 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).

\* \* \* \* \*

#### § 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.

(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.

(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.

(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.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9)).

\* \* \* \* \*

#### § 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  $\pm 20$  percent with a confidence level of 95 percent. The Calibration Error Test and associated calculation procedures set forth in Performance Specifi-

ection 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  $\pm 20$  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.

(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.

(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  $\text{SO}_2$ , 7 for  $\text{NO}_x$ , and 3 for  $\text{O}_2$  and  $\text{CO}_2$ , 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.

(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  $\text{O}_2$  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:

(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 of the Clean Air Act as amended  
(42 U.S.C. 1857c-9).).

\* \* \* \* \*

## Subpart D—Standards of Performance for Fossil-Fuel Fired Steam Generators

### § 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) 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.

### § 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.

(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.

(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.

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

### § 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:

\* \* \* \* \*

(2) Exhibit greater than 20 percent opacity except that a maximum of 40 percent opacity shall be permissible for not more than 3 minutes in any hour.

### § 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) 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.

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

### § 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  $NO_x$ , 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.

(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).

(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

(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.

### § 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)                           | 800                            |
| Liquid                 | 1,000                         | 800                            |
| Solid                  | 1,500                         | 800                            |
| Combinations           | $1,000y + 1,500z$             | $800(x+y) + 1,000z$            |

<sup>1</sup> 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:

$E$ ,  $C$ ,  $F$ , 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 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  $4.15 \times 10^{-4}$  M ng/dscm per ppm ( $2.59 \times 10^{-4}$  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 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,  $F$  =  $2.723 \times 10^{-7}$  dscm/J (10,140 dscf/million Btu) and  $F_c$  =  $0.532 \times 10^{-7}$  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,  $F$  =  $2.637 \times 10^{-7}$  dscm/J (9,820 dscf/million Btu) and  $F_c$  =  $0.486 \times 10^{-7}$  scm  $CO_2$ /J (1,810 scf  $CO_2$ /million Btu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils,  $F$  =  $2.476 \times 10^{-7}$  dscm/J (9,220 dscf/million Btu) and  $F_c$  =  $0.384 \times 10^{-7}$  scm  $CO_2$ /J (1,430 scf  $CO_2$ /million Btu).

(iv) For gaseous fossil fuels,  $F$  =  $2.347 \times 10^{-7}$  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,  $0.322 \times 10^{-7}$  scm  $CO_2$ /J (1,200 scf  $CO_2$ /million Btu) for propane, and  $0.338 \times 10^{-7}$  scm  $CO_2$ /J (1,260 scf  $CO_2$ /million Btu) for butane.

(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).

(vi) For lignite coal as classified according to A.S.T.M. D 388-66,  $F$  =  $2.659 \times 10^{-7}$  dscm/J (9,900 dscf/million Btu) and  $F_c$  =  $0.516 \times 10^{-7}$  scm  $CO_2$ /J (1,920 scf  $CO_2$ /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:

$$F = 10^{-4} \frac{[227.2 (\text{pct. H}) + 95.5 (\text{pct. C}) + 35.6 (\text{pct. S}) + 8.7 (\text{pct. N}) - 28.7 (\text{pct. O})]}{\text{GCV}}$$

(SI units)

$$F = \frac{10^4 [3.64 (\%H) + 1.53 (\%C) + 0.57 (\%S) + 0.14 (\%N) - 0.46 (\%O)]}{\text{GCV}}$$

(English units)

$$F_s = \frac{2.0 \times 10^{-4} (\text{pct. C})}{\text{GCV}}$$

(SI units)

$$F_s = \frac{321 \times 10^4 (\%C)}{\text{GCV}}$$

(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 D1137-63(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 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  $F_s$  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  $F_s$  factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

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

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  $(F_s)_i$  = the applicable  $F$  or  $F_s$  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.

(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 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 of the Clean Air Act as amended (42 U.S.C. 1857c-9).)-

\* \* \* \* \*

#### References:

60.2  
60.7  
60.8  
60.11  
60.13  
Reference Methods 6, 7, 9  
Specifications 1, 2, 3

**Subpart G—Standards of Performance for Nitric Acid Plants**

**§ 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.

**§ 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.

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 re-established 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]

(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).

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857o-9)).

**§ 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<sub>x</sub>, 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.

**§ 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<sub>2</sub>). 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

\* \* \* \* \*

**References:**

60.2  
60.7  
60.8  
60.11  
60.13  
Reference Method 7  
Specification 2

**Subpart H—Standards of Performance for Sulfuric Acid Plants**

**§ 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.

**§ 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.

**§ 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<sub>2</sub>SO<sub>4</sub>.

\* \* \* \* \*

**§ 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), shall be sulfur dioxide (SO<sub>2</sub>). 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 fac-

tor 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]

(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.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9)).

\* \* \* \* \*

**References:**

60.2  
60.7  
60.8  
60.11  
60.13  
Reference Method 8  
Specification 2

## Subpart J—Standards of Performance for Petroleum Refineries

### § 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.

### § 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.

(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.

### § 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:

\* \* \* \* \*

(2) Gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one hour period.

\* \* \* \* \*

### § 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]

### § 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) 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) 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.

(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 set 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.

(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.

(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.

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References:

60.2  
60.7  
60.8  
60.11  
60.13  
Reference Methods 6, 9  
Specifications 1, 2

**Subpart N—Standards of Performance for Iron and Steel Plants<sup>5</sup>**

**§ 60.140 Applicability and designation of affected facility.<sup>6,4</sup>**

(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.

**§ 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 to be discharged 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.

**§ 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  $\pm 250$  Pa ( $\pm 1$  inch water).

(2) 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  $\pm 5$  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 ( $\frac{1}{8}$  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 recalibrated annually, and at other times as the Administrator may require, in accordance with the procedures 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.

**References:**

60.2  
60.7  
60.8  
60.11  
60.13  
Reference Method  
Specifications 1

**Subpart F—Standards of Performance for  
Primary Copper Smelters**

**§ 60.160 Applicability and designation  
of affected facility.**

(a) The provisions of this subpart are applicable 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 sulfide 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.

\* \* \* \* \*

**§ 60.163 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, 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 smelting 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 plant 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.

(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.

(Secs. 111, 114, and 301(a) of the Clean Air Act as amended (42 U.S.C. 1857c-6, 1857c-9, 1857g(a)).)

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**References:**

60.2  
60.7  
60.8  
60.11  
60.13  
Reference Methods 6, 9  
Specifications 1, 2

**Subpart Q—Standards of Performance for  
Primary Zinc Smelters**

**§ 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.

**§ 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.

\* \* \* \* \*

**§ 60.173 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.

(1) 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.

(1) 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 of the Clean Air Act as amended (42 U.S.C. 1857c-9)).

\* \* \* \* \*

**References:**

60.2  
60.7  
60.8  
60.11  
60.13  
Reference Methods 6, 9  
Specifications 1, 2

**Subpart R—Standards of Performance for  
Primary Lead Smelters**

**§ 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 15, 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.

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**§ 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.

(1) 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 of the Clean Air Act as amended (42 U.S.C. 1857c-9).)

\* \* \* \* \*

**References:**

60.2  
60.7  
60.8  
60.11  
60.13  
Reference Methods 6, 9  
Specifications 1, 2

**Subpart T—Standards of Performance for  
the Phosphate Fertilizer Industry: Wet-  
Process Phosphoric Acid Plants**

**§ 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 hot-wells.

(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.

\* \* \* \* \*

**§ 60.203 Monitoring of operations.**

\* \* \* \* \*

(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  $\pm 5$  percent over its operating range.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9)).

\* \* \* \* \*

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**References:**

60.2  
60.7  
60.8  
60.11  
60.13

**Subpart U—Standards of Performance for  
the Phosphate Fertilizer Industry: Super-  
phosphoric Acid Plants**

**§ 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.

**§ 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.

\* \* \* \* \*

**§ 60.213 Monitoring of operations.**

\* \* \* \* \*

(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  $\pm 5$  percent over its operating range.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9)).

\* \* \* \* \*

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**References:**

60.2  
60.7  
60.8  
60.11  
60.13

**Subpart V—Standards of Performance for  
the Phosphate Fertilizer Industry: Diam-  
monium Phosphate Plants**

**§ 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.

**§ 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<sub>2</sub>O<sub>5</sub> feed" means the quantity of phosphorus, expressed as phosphorous pentoxide, fed to the process.

\* \* \* \* \*

**§ 60.223 Monitoring of operations.**

\* \* \* \* \*

(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  $\pm 5$  percent over its operating range.

(Sec. 114 of the Clean Air Act as amended  
(42 U.S.C. 1857c-9).)

\* \* \* \* \*

**References:**

60.2  
60.7  
60.8  
60.11  
60.13

**Subpart W—Standards of Performance for  
the Phosphate Fertilizer Industry: Triple  
Superphosphate Plants**

**§ 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.

**§ 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 run-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.

\* \* \* \* \*

**§ 60.233 Monitoring of operations.**

\* \* \* \* \*

(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  $\pm 5$  percent over its operating range.

(Sec. 114 of the Clean Air Act as amended  
(42 U.S.C. 1857c-9)).

\* \* \* \* \*

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**References:**

60.2  
60.7  
60.8  
60.11  
60.13

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

**§ 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.

**§ 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.

\* \* \* \* \*

**§ 60.243 Monitoring of operations.**

\* \* \* \* \*

(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 system. The monitoring device shall have an accuracy of  $\pm 5$  percent over its operating range.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9)).

\* \* \* \* \*

**References:**

60.2  
60.7  
60.8  
60.11  
60.13

**Subpart Y—Standards of Performance for  
Coal Preparation Plants**

**§ 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 24, 1974, is subject to the requirements of this subpart.

**§ 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, sub-bituminous, 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.

\* \* \* \* \*

**§ 60.253 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  $\pm 3^\circ$  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  $\pm 1$  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  $\pm 5$  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).

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9)).

\* \* \* \* \*

**References:**

60.2  
60.7  
60.8  
60.11  
60.13

**Subpart Z—Standards of Performance for Ferroalloy Production Facilities**

**§ 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.

**§ 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.

(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:

\* \* \* \* \*

(3) Exit from a control device and exhibit 15 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 cause to be discharged into the atmosphere from any dust-handling equipment any gases which exhibit 10 percent opacity or greater.

\* \* \* \* \*

**§ 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.

\* \* \* \* \*

**§ 60.265 Monitoring of operations.**

\* \* \* \* \*

(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  $\pm 5$  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  $\pm 10$  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  $\pm 5$  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 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 repre-

sentative 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. 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 of the Clean Air Act as amended  
(42 U.S.C. 1857c-9).).

\* \* \* \* \*

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#### References:

60.2  
60.7  
60.8  
60.11  
60.13

**Subpart AA—Standards of Performance  
for Steel Plants: Electric Arc Furnaces**

**§ 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 21, 1974, is subject to the requirements of this subpart.

**§ 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 prerduced 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 commencement to tilt, whichever is longer.

\* \* \* \* \*

**§ 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:

\* \* \* \* \*

(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 of the Clean Air Act as amended (42 U.S.C. 1857c-9).)

\* \* \* \* \*

**References:**

60.2  
60.7  
60.8  
60.11  
60.13

**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  $\pm 1$  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  $\pm 500$  pascals (ca.  $\pm 2$  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  $\pm 15$  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:

$$C_{\text{corr}} = C_{\text{meas}} \times (21 - X/21 - Y)$$

where:

$C_{\text{corr}}$  = the concentration corrected for oxygen.

$C_{\text{meas}}$  = 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/m<sup>3</sup> PPM for metric units  
= 0.08844 lb/ft<sup>3</sup> PPM for English units

$F_{MeSH}$  = 0.00200 g/m<sup>3</sup> PPM for metric units  
= 0.1248 lb/ft<sup>3</sup> PPM for English units

$F_{DMS}$  = 0.002583 g/m<sup>3</sup> PPM for metric units  
= 0.1612 lb/ft<sup>3</sup> PPM for English units

$F_{DMDS}$  = 0.003917 g/m<sup>3</sup> PPM for metric units  
= 0.2445 lb/ft<sup>3</sup> 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:

$$GLS = 100 \left( C_{Na_2S} + C_{NaOH} + C_{Na_2CO_3} \right)$$

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

**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 sam-

**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  $\pm 250$  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  $\pm 5$  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  $\pm 5$  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  $\pm 10$  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  $\pm 5$  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).)

## 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 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 ( $\text{mg}$ ) of  $\text{SO}_2/\text{m}^3$  ( $2.12 \times 10^{-3}$  lb/ft<sup>3</sup>). Although no upper limit has been established, tests have shown that concentrations as high as 80,000  $\text{mg}/\text{m}^3$  of  $\text{SO}_2$  can be collected efficiently in two midge impingers, each containing 15 milliliters of 3 percent hydrogen peroxide, at a rate of 1.0 lpm for 30 minutes. Based on theoretical calculations, the upper concentration limit in a 30-liter sample is about 93,300  $\text{mg}/\text{m}^3$ .

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  $\text{SO}_2$  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  $\text{SO}_2$  to form particulate sulfate 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 5 in place of the midge impinger equipment of Method 6. However, the Method 6 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 6.

The tester also has the option of determining  $\text{SO}_2$  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 5 isopropanol-filter-peroxide system. The analysis for  $\text{SO}_2$  must be consistent with the procedure in Method 5.

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 midge 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 midge impingers. The bubbler and midge 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 midge impinger may be used in place of the midge 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  $\text{SO}_2$ .

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  $1^\circ\text{C}$  ( $2^\circ\text{F}$ ).

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  $175^\circ\text{C}$  ( $350^\circ\text{F}$ ) for 3 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 diaphragm 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  $2^\circ\text{C}$  ( $3.6^\circ\text{F}$ ).

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 862 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  $\text{KMnO}_4$  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 862 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-arsenophenylazo)-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 [ $\text{Ba}(\text{ClO}_4)_3 \cdot 3\text{H}_2\text{O}$ ] in 200 ml distilled water and dilute to 1 liter with isopropanol. Alternatively, 1.22 g of [ $\text{BaCl}_2 \cdot 2\text{H}_2\text{O}$ ] 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  $\pm 0.0002$  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 midge bubbler and 15 ml of 3 percent hydrogen peroxide into each of the first two midge impingers. Leave the final midge 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 ( $\pm 10$  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  $20^\circ\text{C}$  ( $68^\circ\text{F}$ ) 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 midge impinger with 15 ml of 3 percent  $\text{H}_2\text{O}_2$ . 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 midge bubbler. Pour the contents of the midge impingers into a leak-free polyethylene bottle for shipment. Rinse the three midge 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. Standardise 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, 298° K (528° R).  
 $V_s$  = 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).

$V_{sol}$  = 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).

$V_{10}$  = Volume of barium perchlorate titrant used for the blank, ml.

$Y$  = Dry gas meter calibration factor.

32.05 = 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:

$K_1 = 0.3828 \text{ } ^\circ\text{K}/\text{mm Hg}$  for metric units.

$= 17.64 \text{ } ^\circ\text{R}/\text{in. Hg}$  for English units.

6.3 Sulfur dioxide concentration.

$$C_{SO_2} = K_2 \frac{(V_t - V_{10}) N \left( \frac{V_{sol}}{V_s} \right)}{V_m(Std)}$$

Equation 6-2

where:

$K_2 = 32.05 \text{ mg/meq.}$  for metric units.

$= 7.061 \times 10^{-3} \text{ lb/meq.}$  for English units.

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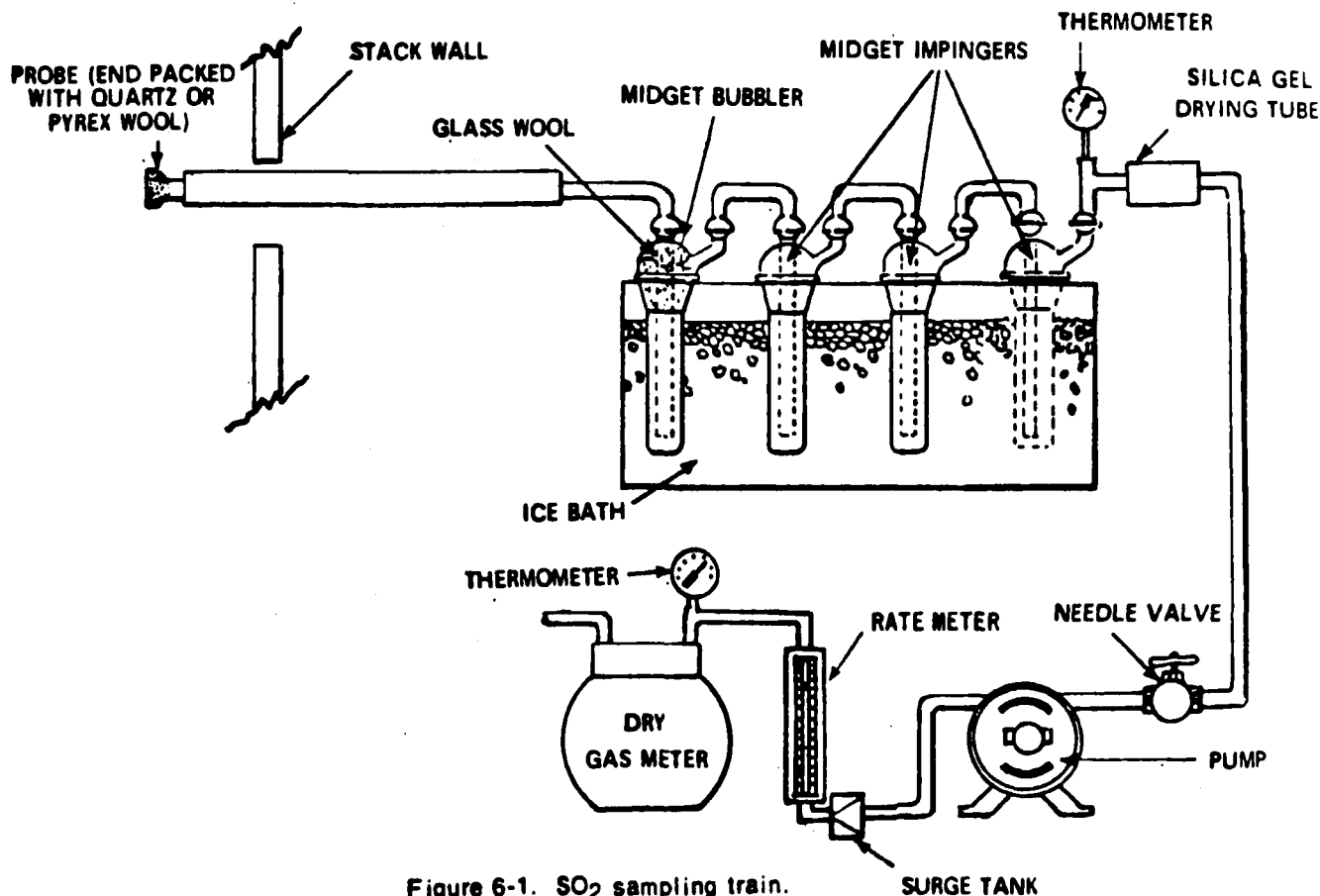


Figure 6-1.  $SO_2$  sampling train.

SURGE TANK

**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  $\text{NO}_x$  (as  $\text{NO}_2$ ) 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  $\pm 3.0$  percent and collecting a sufficient sample volume to allow analytical reproducibility to within  $\pm 5$  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<sup>®</sup> tubing may also be used for the probe. Heating is not necessary if the probe remains dry during the purging period.

<sup>1</sup> 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  $1^\circ\text{C}$  ( $5^\circ\text{F}$ ) intervals from  $-5$  to  $60^\circ\text{C}$  ( $23$  to  $125^\circ\text{F}$ ).

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  $\pm 2.5$  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 25-55 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 Burring 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 5 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 (Nalgae 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  $70^\circ\text{C}$  ( $160^\circ\text{F}$ ) 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  $\text{KNO}_3$  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.

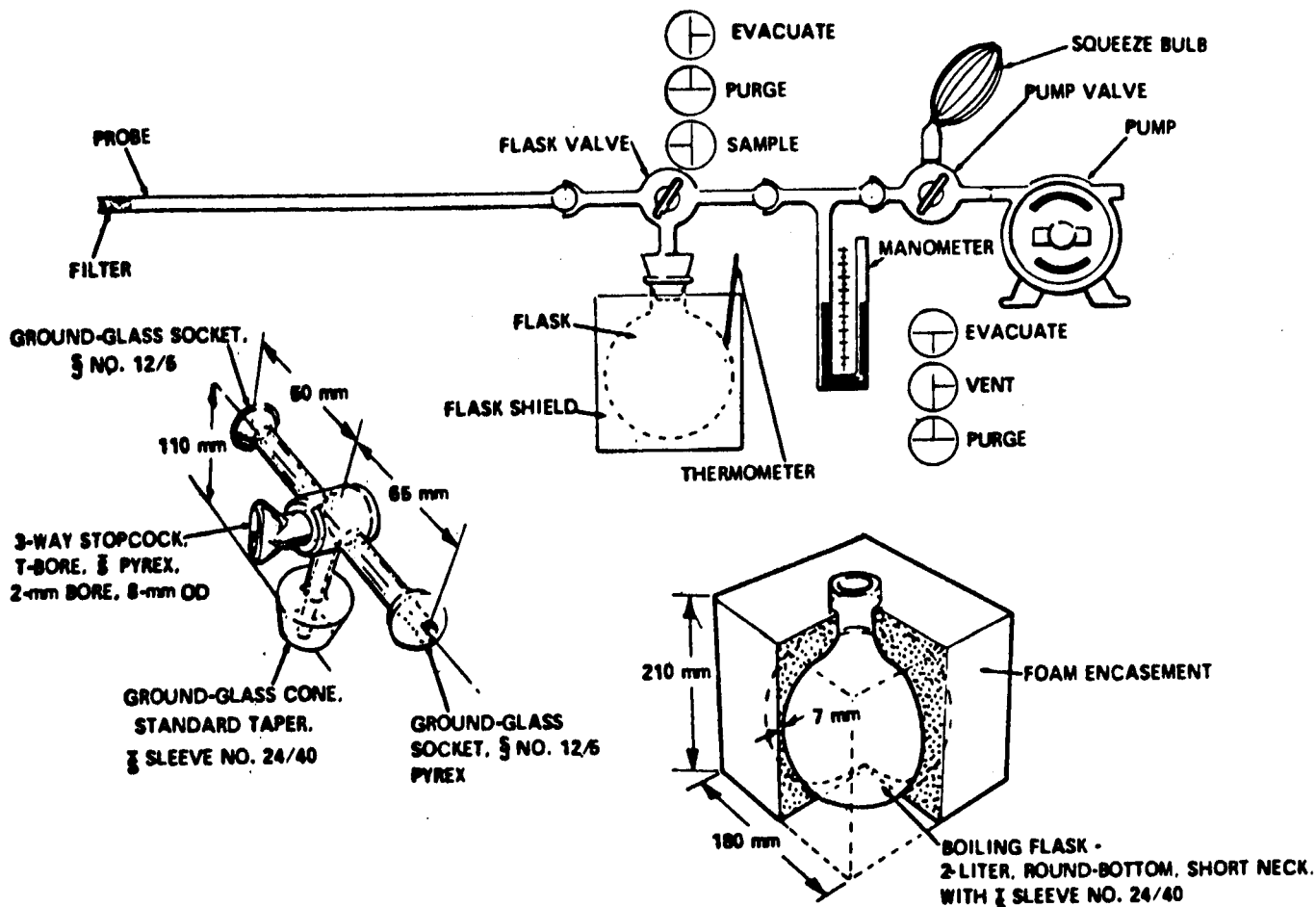


Figure 7-1. Sampling train, flask valve, and flask.

## 2. 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.

2.1 Sampling. To prepare the absorbing solution, cautiously add 2.8 ml concentrated  $\text{H}_2\text{SO}_4$  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.

2.2 Sample Recovery. Two reagents are required for sample recovery:

2.2.1 Sodium Hydroxide (1N). Dissolve 40 g NaOH in deionized, distilled water and dilute to 1 liter.

2.2.2 Water Deionized, distilled to conform to ASTM specification D1193-74, Type 3. At the option of the analyst, the  $\text{KMnO}_4$  test for oxidizable organic matter may be omitted when high concentrations of organic matter are not expected to be present.

2.3 Analysis. For the analysis, the following reagents are required:

2.3.1 Fuming Sulfuric Acid, 15 to 18 percent by weight free sulfur trioxide. HANDLE WITH CAUTION.

2.3.2 Phenol, White solid.

2.3.3 Sulfuric Acid, Concentrated, 95 percent minimum assay. HANDLE WITH CAUTION.

2.3.4 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.

2.3.5 Standard  $\text{KNO}_3$  Solution. Dissolve exactly 2.096 g of dried potassium nitrate ( $\text{KNO}_3$ ) in deionized, distilled water and dilute to 1 liter with deionized, distilled water in a 1,000-ml volumetric flask.

2.3.6 Working Standard  $\text{KNO}_3$  Solution. Dilute 10 ml of a standard solution to 100 ml with deionized, distilled water. One milliliter of the working standard solution is equivalent to 100  $\mu\text{g}$  nitrogen dioxide ( $\text{NO}_2$ ).

2.3.7 Water Deionized, distilled as in Section 2.2.

2.3.8 Phenol-disulfonic 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 ( $P_i$ ) 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  $\text{NO}$  to  $\text{NO}_2$  (e.g., an applicable subset of the standard may require taking a sample of a calibration gas mixture of  $\text{NO}$  in  $\text{N}_2$ ), 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 60 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 ( $P_i$ ) 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 (1N), 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 porcelain 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 phenol-disulfonic 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 10-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- $\mu\text{g}$   $\text{NO}_2$  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  $\pm 0.1$  ml. Record this volume on the flask.

5.2 Optimum Wavelength Determination. For both fixed and variable wavelength spectrophotometers, calibrate against standard certified wavelength of 410 nm, every 6 months. Alternatively, for variable wavelength spectrophotometers, scan the spectrum between 400 and 415 nm using a 200- $\mu\text{g}$   $\text{NO}_2$  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  $K$ . Add 0.0, 1.0, 2.0, 3.0, and 4.0 ml of the  $\text{KNO}_3$  working standard solution (1 ml = 100  $\mu\text{g}$   $\text{NO}_2$ ) 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:

$$K = 100 \frac{A_1 + 2A_2 + 3A_3 + 4A_4}{A_1^2 + A_2^2 + A_3^2 + A_4^2}$$

Equation 7-1

where:

$K$  = Calibration factor  
 $A_1$  = Absorbance of the 100- $\mu\text{g}$   $\text{NO}_2$  standard  
 $A_2$  = Absorbance of the 200- $\mu\text{g}$   $\text{NO}_2$  standard  
 $A_3$  = Absorbance of the 300- $\mu\text{g}$   $\text{NO}_2$  standard  
 $A_4$  = Absorbance of the 400- $\mu\text{g}$   $\text{NO}_2$  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  $\text{NO}_2$ , as  $\text{NO}_2$ , 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)  
 $K$  = Spectrophotometer calibration factor  
 $m$  = Mass of  $\text{NO}_2$ , as  $\text{NO}_2$ , in gas sample,  $\mu\text{g}$   
 $P_i$  = Final absolute pressure of flask, mm Hg (in. Hg)  
 $P_s$  = 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, 273° K (528° R)  
 $V_s$  = Sample volume at standard conditions (dry basis), ml  
 $V_f$  = Volume of flask and valve, ml  
 $V_r$  = Volume of absorbing solution, 25 ml  
 $2 = 80/25$ , 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

$$V_s = \frac{T_{std}}{P_{std}} (V_f - V_r) \left[ \frac{P_i}{T_f} - \frac{P_s}{T_i} \right] = K_1 (V_f - 25 \text{ ml}) \left[ \frac{P_i}{T_f} - \frac{P_s}{T_i} \right]$$

Equation 7-2

where:

$$K_1 = 0.3858 \frac{^\circ\text{K}}{\text{mm Hg}} \text{ for metric units}$$

$$= 17.64 \frac{^\circ\text{R}}{\text{in. Hg}} \text{ for English units}$$

6.3 Total  $\mu\text{g}$   $\text{NO}_2$  per sample.

$$m = 2 K_1 A F$$

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.

$$C = K_2 \frac{m}{V_s}$$

Equation 7-4

where:

$$K_2 = 10^3 \frac{\text{mg}/\text{m}^3}{\mu\text{g}/\text{ml}} \text{ for metric units}$$

$$= 6.243 \times 10^{-3} \frac{\text{lb}/\text{scf}}{\mu\text{g}/\text{ml}} \text{ for English units}$$

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# 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-thorium 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 ( $0.03 \times 10^{-3}$  pounds/cubic foot) for sulfur trioxide and 1.2 mg/m<sup>3</sup> ( $0.74 \times 10^{-3}$  lb/ft<sup>3</sup>) 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 m<sup>3</sup> (35.3 ft<sup>3</sup>) gas sample is about 12,500 mg/m<sup>3</sup> ( $7.7 \times 10^{-4}$  lb/ft<sup>3</sup>). 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<sub>2</sub> and SO<sub>3</sub> (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-4581 (Changes from the APTD-4581 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-4576. Since correct usage is important in obtaining valid results, all users should read the APTD-4576 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.

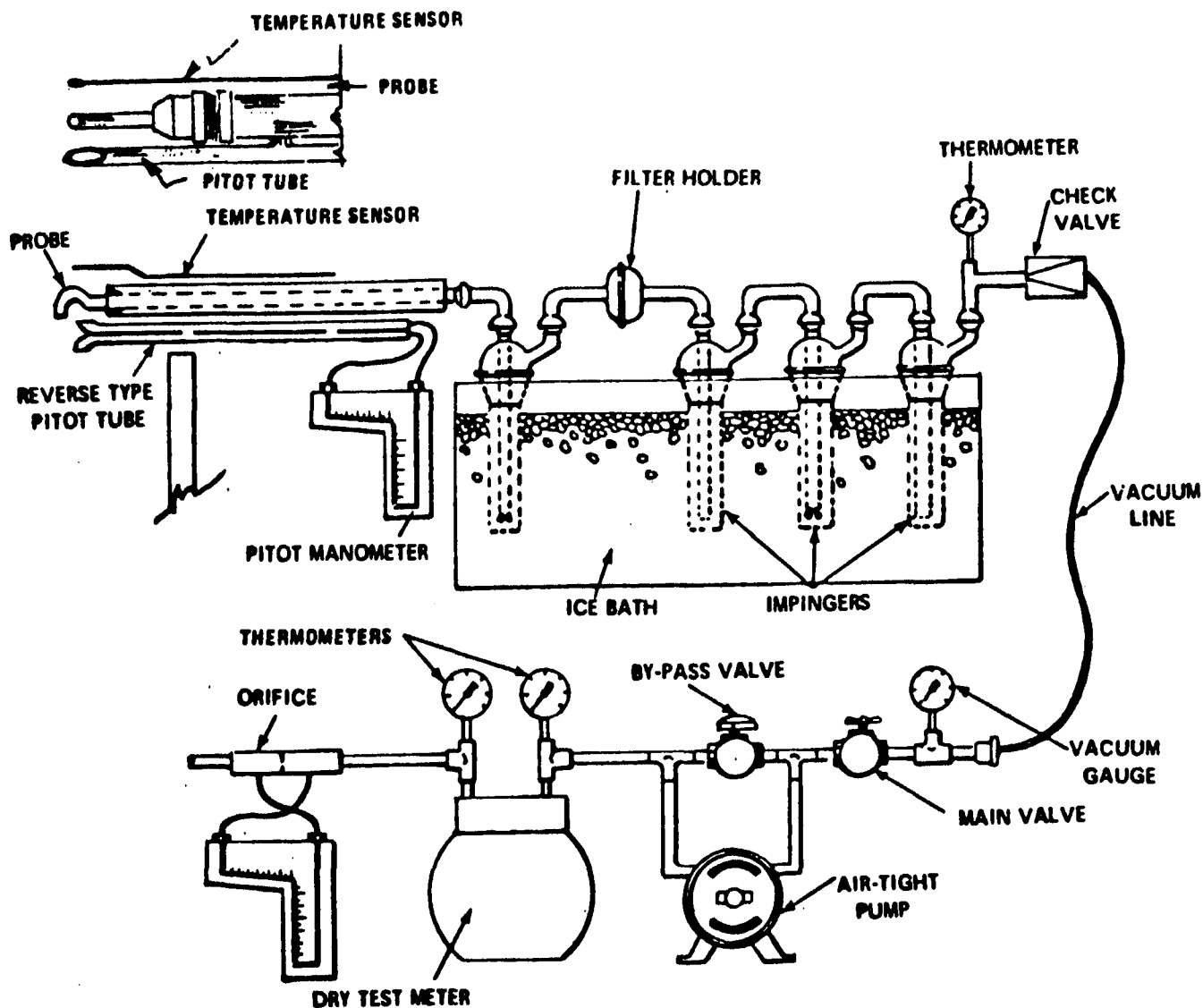


Figure 8-1. Sulfuric acid mist sampling train.

- ### 3. Regents

## 2.1 Sampling

**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 a erroneously high sulfuric acid mist measurement. Use the following test for detecting peroxides in which 10 ml. of isopropanol, 50 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 552 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.

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3.3.5 Sulfuric Acid Standard (0.0100 N). Purchase or standardize to  $\pm 0.0002$  N against 0.0100 N NaOH that has previously been standardized against primary standard potassium acid phthalate.

- 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

|  |
|--|
|  |
|--|

### 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<sup>3</sup>/min, (cfm) \_\_\_\_\_

PROBE LINER MATERIAL \_\_\_\_\_

FILTER NO. \_\_\_\_\_

**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 verbiage 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 8-5. The sampling rate shall not exceed 0.080 m<sup>3</sup>/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 hot 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 thion 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 0.3 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 thion 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 0.3 ml, whichever is greater.

**4.3.3 Blanks.** Prepare blanks by adding 2 to 4 drops of thion 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 26 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, m<sup>2</sup> (ft<sup>2</sup>).
- $B_w$  = Water vapor in the gas stream, proportion by volume.
- $CH_2SO_4$  = Sulfuric acid (including SO<sub>3</sub>) concentration, g/dacm (lb/dacft).
- $CWO_2$  = Sulfur dioxide concentration, g/dacm (lb/dacft).
- $I$  = 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).
- $T_n$  = 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 (32° R).
- $V_n$  = Volume of sample aliquot titrated, 100 ml for H<sub>2</sub>SO<sub>4</sub> and 10 ml for SO<sub>3</sub>.
- $V_l$  = Total volume of liquid collected in impingers and silica gel, ml.
- $V_n$  = Volume of gas sample as measured by dry gas meter, dcm (dcf).
- $V_n(Std)$  = Volume of gas sample measured by the dry gas meter corrected to standard conditions, dcm (dcf).
- $v$  = Average stack gas velocity, calculated by Method 2, Equation 2-6, 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.
- $V_{t1}$  = Volume of barium perchlorate titrant used for the blank, ml.
- $Y$  = Dry gas meter calibration factor.
- $\Delta H$  = Average pressure drop across orifice meter, mm (in.) H<sub>2</sub>O.
- $\theta$  = 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.

$$V_n(Std) = V_n Y \left( \frac{T_{std}}{T_n} \right) \frac{P_{bar} + \left( \frac{\Delta H}{13.6} \right)}{P_{std}} \\ = K_1 V_n Y \frac{P_{bar} + (\Delta H/13.6)}{T_n} \quad \text{Equation 8-1}$$

where:

$K_1$  = 0.2835° 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  $V_n$  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 8-2 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). Cal-

culate the moisture content of the stack gas, using Equation 8-3 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<sub>3</sub>) concentration.

$$C_{H_2SO_4} = K_2 \frac{N(V_l - V_n) \left( \frac{V_{soln}}{V_n} \right)}{V_n(Std)} \quad \text{Equation 8-2}$$

where:

$K_2$  = 0.04904 g/milliequivalent for metric units.

= 1.061 × 10<sup>-3</sup> lb/meq for English units.

**6.6** Sulfur dioxide concentration.

$$C_{SO_2} = K_2 \frac{N(V_l - V_n) \left( \frac{V_{soln}}{V_n} \right)}{V_n(Std)} \quad \text{Equation 8-3}$$

where:

$K_2$  = 0.03203 g/meq for metric units.

= 7.061 × 10<sup>-4</sup> lb/meq for English units.

**6.7** Isokinetic Variation.

**6.7.1** Calculation from raw data.

$$I = \frac{100 T_n [K_1 V_l + (V_n/T_n) P_{bar} + \Delta H/13.6]}{60 \theta V_n P_s A_n} \quad \text{Equation 8-4}$$

where:

$K_1$  = 0.003464 mm Hg·m<sup>3</sup>/ml·°K for metric units.

= 0.002676 in. Hg·ft<sup>3</sup>/ml·°R for English units.

**6.7.2** Calculation from intermediate values.

$$I = \frac{T_n V_n(Std) P_{std} 100}{T_{std} v_n A_n P_s 60 (1 - B_w)} \\ = K_3 \frac{T_n V_n(Std)}{P_s v_n A_n \theta (1 - B_w)} \quad \text{Equation 8-5}$$

where:

$K_3$  = 4.320 for metric units.

= 0.09450 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.

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## 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 luminance 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 luminance 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<sup>1</sup> 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.

<sup>1</sup> For a set, positive error=average opacity determined by observers/25 observations—average opacity determined from transmissionometer'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 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  $\pm 1$  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  $\theta$ =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  $\theta$ =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 calibrated 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 Welsburt, Melvin L., 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

PAGE 1 OF 1

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 \_\_\_\_\_

21

[illegible]

### SUMMARY OF AVERAGE OPACITY

[illegible]

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 \_\_\_\_\_  
 LOCATION \_\_\_\_\_  
 TEST NUMBER \_\_\_\_\_  
 DATE \_\_\_\_\_

OBSERVER \_\_\_\_\_  
 TYPE FACILITY \_\_\_\_\_  
 POINT OF EMISSIONS \_\_\_\_\_

| Hr. | Min. | Seconds |    |    |    | STEAM PLUME<br>(check if applicable) |          | COMMENTS |
|-----|------|---------|----|----|----|--------------------------------------|----------|----------|
|     |      | 0       | 15 | 30 | 45 | Attached                             | Detached |          |
|     | 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 \_\_\_\_\_  
 LOCATION \_\_\_\_\_  
 TEST NUMBER \_\_\_\_\_  
 DATE \_\_\_\_\_

OBSERVER \_\_\_\_\_  
 TYPE FACILITY \_\_\_\_\_  
 POINT OF EMISSIONS \_\_\_\_\_

| Hr. | Min. | Seconds |    |    |    | STEAM PLUME<br>(check if applicable) |          | COMMENTS |
|-----|------|---------|----|----|----|--------------------------------------|----------|----------|
|     |      | 0       | 15 | 30 | 45 | Attached                             | Detached |          |
|     | 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]

## APPENDIX B—PERFORMANCE SPECIFICATIONS

**Performance Specification J**—Performance specifications and specification test procedures for transmissometer systems for continuous measurement of the opacity of stack 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, 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  $\pm 3$  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<br>(percent opacity) | Calibrated filter optical densities<br>with equivalent opacity in<br>parenthesis |               |                |
|---------------------------------|----------------------------------------------------------------------------------|---------------|----------------|
|                                 | Low-<br>range                                                                    | Mid-<br>range | High-<br>range |
| 50.....                         | 0.1 (20)                                                                         | 0.2 (37)      | 0.5 (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 (87.5)      |

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 is 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 3.2.1.

**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

FIGURE 9-2 OBSERVATION RECORD

PAGE \_\_\_\_ OF \_\_\_\_

COMPANY \_\_\_\_\_  
 LOCATION \_\_\_\_\_  
 TEST NUMBER \_\_\_\_\_  
 DATE \_\_\_\_\_

OBSERVER \_\_\_\_\_  
 TYPE FACILITY \_\_\_\_\_  
 POINT OF EMISSIONS \_\_\_\_\_

| Hr. | Min. | Seconds |    |    |    | STEAM PLUME<br>(check if applicable) |          | COMMENTS |
|-----|------|---------|----|----|----|--------------------------------------|----------|----------|
|     |      | 0       | 15 | 30 | 45 | Attached                             | Detached |          |
|     | 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 \_\_\_\_\_  
 LOCATION \_\_\_\_\_  
 TEST NUMBER \_\_\_\_\_  
 DATE \_\_\_\_\_

OBSERVER \_\_\_\_\_  
 TYPE FACILITY \_\_\_\_\_  
 POINT OF EMISSIONS \_\_\_\_\_

| Hr. | Min. | Seconds |    |    |    | STEAM PLUME<br>(check if applicable) |          | COMMENTS |
|-----|------|---------|----|----|----|--------------------------------------|----------|----------|
|     |      | 0       | 15 | 30 | 45 | Attached                             | Detached |          |
|     | 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;8:46 am]

## 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.**

### 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  $\pm 3$  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<br>(percent opacity) | Calibrated filter optical densities<br>with equivalent opacity in<br>parenthesis |               |                |
|---------------------------------|----------------------------------------------------------------------------------|---------------|----------------|
|                                 | Low-<br>range                                                                    | Mid-<br>range | High-<br>range |
| 50.....                         | 0.1 (20)                                                                         | 0.2 (37)      | 0.3 (50)       |
| 60.....                         | .1 (20)                                                                          | .2 (37)       | .3 (50)        |
| 70.....                         | .1 (20)                                                                          | .3 (50)       | .4 (67)        |
| 80.....                         | .1 (20)                                                                          | .3 (50)       | .6 (75)        |
| 90.....                         | .1 (20)                                                                          | .4 (60)       | .7 (86)        |
| 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 is 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 3.2.1.

**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:

$$\log(1 - O_1) = (L_1/L_0) \log(1 - O_0)$$

where:

$O_1$  = the opacity of the effluent based upon  $L_1$ .

$O_0$  = the opacity of the effluent based upon  $L_0$ .

$L_1$  = the emission outlet pathlength.

$L_0$  = the monitor pathlength.

#### 8. Optical Design Specifications.

The optical design specifications set forth in Section 8.1 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.

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 3-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 3-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. |
| b. Zero drift (24 h).....        | <2 pct opacity. |
| c. Calibration drift (24 h)..... | <2 pct opacity. |
| d. Response time.....            | 10 s (maximum). |
| e. Operational test period.....  | 168 h.          |

<sup>1</sup> 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 retroreflector 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 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.

$$\bar{x} = \frac{1}{n} \sum_{i=1}^n x_i \quad \text{Equation 1-1}$$

where  $x_i$  = absolute value of the individual measurements.

$\Sigma$  = 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:

$$C.I._{95} = \frac{t_{0.975}}{n\sqrt{n-1}} \sqrt{n(\Sigma x_i^2) - (\Sigma x_i)^2} \quad \text{Equation 1-2}$$

where

$\Sigma x_i$  = sum of all data points,

$t_{0.975} = t_{1-\alpha/2}$ , 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 1.975

| n | 1.975  | n  | 1.975 |
|---|--------|----|-------|
| 2 | 12.706 | 10 | 2.262 |
| 3 | 4.303  | 11 | 2.226 |
| 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 accord-

ing 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.

| 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.

| Low<br>Range _____ % opacity<br>Span Value _____ % opacity | Mid<br>Range _____ % opacity  | High<br>Range _____ % opacity         |
|------------------------------------------------------------|-------------------------------|---------------------------------------|
| Date of Test _____ Location of Test _____                  |                               |                                       |
| Calibrated Filter <sup>1</sup>                             | Analyzer Reading<br>% Opacity | Differences <sup>2</sup><br>% Opacity |
| 1                                                          |                               |                                       |
| 2                                                          |                               |                                       |
| 3                                                          |                               |                                       |
| 4                                                          |                               |                                       |
| 5                                                          |                               |                                       |
| 6                                                          |                               |                                       |
| 7                                                          |                               |                                       |
| 8                                                          |                               |                                       |
| 9                                                          |                               |                                       |
| 10                                                         |                               |                                       |
| 11                                                         |                               |                                       |
| 12                                                         |                               |                                       |
| 13                                                         |                               |                                       |
| 14                                                         |                               |                                       |
| 15                                                         |                               |                                       |
| Mean difference                                            | Low _____                     | Mid _____ High _____                  |
| Confidence interval                                        | Low _____                     | Mid _____ High _____                  |
| Calibration error = Mean Difference <sup>3</sup> + C.I.    | Low _____                     | Mid _____ High _____                  |

<sup>1</sup>Low, mid or high range

<sup>2</sup>Calibration filter opacity - analyzer reading

<sup>3</sup>Absolute value

Figure 1-1. Calibration Error Test



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 <sup>1</sup>                 | ≤20 pct of the mean value of the reference method test data.   |
| 2. Calibration error <sup>1</sup>        | ≤5 pct of each (50 pct, 90 pct) calibration gas mixture value. |
| 3. Zero drift (2 h) <sup>1</sup>         | 2 pct of span                                                  |
| 4. Zero drift (24 h) <sup>1</sup>        | Do.                                                            |
| 5. Calibration drift (2 h) <sup>1</sup>  | Do.                                                            |
| 6. Calibration drift (24 h) <sup>1</sup> | 2.5 pct. of span                                               |
| 7. Response time                         | 15 min maximum.                                                |
| 8. Operational period                    | 168 h minimum.                                                 |

<sup>1</sup> 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<sub>x</sub> analyzers that oxidize nitric oxide (NO) to nitrogen dioxide (NO<sub>2</sub>), the response time test under paragraph 6.3 of this method shall be performed using nitric oxide (NO) span gas. Other tests for NO<sub>x</sub> 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 written 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<sub>2</sub> and 7 for NO<sub>x</sub>. 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., 50%, 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 addi-

tional 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<sub>x</sub> continuous monitoring systems, make 27 NO<sub>x</sub> 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<sub>2</sub> continuous monitoring systems, make nine SO<sub>2</sub> 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.

$$\bar{x} = \frac{1}{n} \sum_{i=1}^n x_i \quad \text{Equation 2-1}$$

where:

$x_i$  = absolute value of the measurements,  
 $\Sigma$  = 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:

$$C.I._{.95} = \frac{t_{.975}}{n\sqrt{n-1}} \sqrt{n(\Sigma x_i^2) - (\Sigma x_i)^2} \quad \text{Equation 2-2}$$

where:

$\Sigma x_i$  = 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  |
|----|--------|
| 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  $\text{NO}_x$ ) 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, paragraph 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 |
|-------------------------------------------------|-----------------------|
| <b>High-Range Calibration Gas Mixture</b>       |                       |
| Sample 1                                        | _____ ppm             |
| Sample 2                                        | _____ ppm             |
| Sample 3                                        | _____ ppm             |
| Average                                         | _____ ppm             |
| <b>High-Range (ppm) Calibration Gas Mixture</b> |                       |
| 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, <sup>1</sup> ppm |
|-------|------------------------------------|---------------------------------|-------------------------------|
| 1     |                                    |                                 |                               |
| 2     |                                    |                                 |                               |
| 3     |                                    |                                 |                               |
| 4     |                                    |                                 |                               |
| 5     |                                    |                                 |                               |
| 6     |                                    |                                 |                               |
| 7     |                                    |                                 |                               |
| 8     |                                    |                                 |                               |
| 9     |                                    |                                 |                               |
| 10    |                                    |                                 |                               |
| 11    |                                    |                                 |                               |
| 12    |                                    |                                 |                               |
| 13    |                                    |                                 |                               |
| 14    |                                    |                                 |                               |
| 15    |                                    |                                 |                               |

Mid

High

Mean difference \_\_\_\_\_

Confidence interval + +

Calibration error =  $\frac{\text{Mean Difference}^2 + \text{C.I.}}{\text{Average Calibration Gas Concentration}} \times 100$  % %

<sup>1</sup> Calibration gas concentration - measurement system reading

<sup>2</sup> Absolute value

Figure 2-2. Calibration Error Determination

| Test No. | Date and Time | Reference Method Samples       |                   |                   |                   |                         | Analyzer 1-Hour Average (ppm)* |                 | Difference (ppm) |                 |
|----------|---------------|--------------------------------|-------------------|-------------------|-------------------|-------------------------|--------------------------------|-----------------|------------------|-----------------|
|          |               | SO <sub>2</sub> Sample 1 (ppm) | NO Sample 1 (ppm) | NO Sample 2 (ppm) | NO Sample 3 (ppm) | NO Sample Average (ppm) | SO <sub>2</sub>                | NO <sub>x</sub> | SO <sub>2</sub>  | NO <sub>x</sub> |
| 1        |               |                                |                   |                   |                   |                         |                                |                 |                  |                 |
| 2        |               |                                |                   |                   |                   |                         |                                |                 |                  |                 |
| 3        |               |                                |                   |                   |                   |                         |                                |                 |                  |                 |
| 4        |               |                                |                   |                   |                   |                         |                                |                 |                  |                 |
| 5        |               |                                |                   |                   |                   |                         |                                |                 |                  |                 |
| 6        |               |                                |                   |                   |                   |                         |                                |                 |                  |                 |
| 7        |               |                                |                   |                   |                   |                         |                                |                 |                  |                 |
| 8        |               |                                |                   |                   |                   |                         |                                |                 |                  |                 |
| 9        |               |                                |                   |                   |                   |                         |                                |                 |                  |                 |

Mean reference method test value (SO<sub>2</sub>) \_\_\_\_\_

Mean reference method test value (NO<sub>x</sub>) \_\_\_\_\_

Mean of the differences \_\_\_\_\_

95% Confidence intervals = ± \_\_\_\_\_ ppm (SO<sub>2</sub>) = ± \_\_\_\_\_ ppm (NO<sub>x</sub>)

Accuracy =  $\frac{\text{Mean of the differences} + 95\% \text{ confidence interval}}{\text{Mean reference method value}} \times 100 =$  \_\_\_\_\_ % (SO<sub>2</sub>) = \_\_\_\_\_ % (NO<sub>x</sub>)

\* Explain and report method used to determine integrated averages

Figure 2-3. Accuracy Determination (SO<sub>2</sub> and NO<sub>x</sub>)

| Data Set No. | Time  |     | Date | Zero Reading | Zero Drift ( $\Delta$ Zero) | Span Reading | Span Drift ( $\Delta$ Span) | Calibration Drift (Span - Zero) |
|--------------|-------|-----|------|--------------|-----------------------------|--------------|-----------------------------|---------------------------------|
|              | Begin | End |      |              |                             |              |                             |                                 |
| 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.

[illegible]

|                                               |                                                                                                                                      |
|-----------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------|
| 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 | = $\left[ \frac{\text{average upscale minus average downscale}}{\text{slower time}} \right] \times 100\% = \underline{\hspace{2cm}}$ |

Figure 2-6. Response Time

**Performance Specification 3—Performance specifications and specification test procedures for monitors of CO<sub>2</sub> and O<sub>2</sub> 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<sub>2</sub>, 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 correspond-

ing 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<sub>2</sub> or NO<sub>x</sub> 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) <sup>1</sup> .....         | ≤0.4 pct O <sub>2</sub> or CO <sub>2</sub> |
| 2. Zero drift (24 h) <sup>1</sup> .....        | ≤0.5 pct O <sub>2</sub> or CO <sub>2</sub> |
| 3. Calibration drift (2 h) <sup>1</sup> .....  | ≤0.4 pct O <sub>2</sub> or CO <sub>2</sub> |
| 4. Calibration drift (24 h) <sup>1</sup> ..... | ≤0.5 pct O <sub>2</sub> or CO <sub>2</sub> |
| 5. Operational period.....                     | 168 h minimum                              |
| 6. Response time.....                          | 10 min.                                    |

<sup>1</sup> 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 18 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<sub>2</sub> or O<sub>2</sub> 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.

$$\bar{x} = \frac{1}{n} \sum_{i=1}^n x_i \quad \text{Equation 3-1}$$

where:

$x_i$  = absolute value of the measurements,  
 $\Sigma$  = 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:

$$C.I._{95} = \frac{t_{.975}}{n\sqrt{n-1}} \sqrt{n(\Sigma x_i^2) - (\Sigma x_i)^2} \quad \text{Equation 3-2}$$

where:

$\Sigma X$  = sum of all data points,  
 $t_{.975} = t_{1-\alpha/2}$ , and

C.I.<sub>95</sub> = 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 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. 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. 16(c) (2) of Pub. L. 91-604, 85 Stat. 1713 (42 U.S.C. 1857g)).

| Data Set No. | Time Begin | Time End | Data | Zero Reading | Zero Drift ( $\Delta$ Zero) | Span Reading | Span Drift ( $\Delta$ Span) | Calibration Drift ( $\Delta$ Span - $\Delta$ Zero) |
|--------------|------------|----------|------|--------------|-----------------------------|--------------|-----------------------------|----------------------------------------------------|
| 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).

[illegible]

|                                                                                                                                         |                                          |
|-----------------------------------------------------------------------------------------------------------------------------------------|------------------------------------------|
| 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                                                                              |                                          |
| $\% \text{ deviation from slower} = \frac{\text{average upscale minus average downscale}}{\text{system average response}} \times 100\%$ |                                          |
| $= \underline{\hspace{2cm}}$                                                                                                            |                                          |

Figure 3-3. Response

(Sec. 114 of the Clean Air Act as amended  
(42 U.S.C. 1857c-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

\* \* \* \* \*

#### 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 regulations 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.

\* \* \* \* \*

Dated: February 22, 1974.

RUSSELL E. TRAIN,  
Administrator.

FEDERAL REGISTER, VOL. 39, NO. 47—  
FRIDAY, MARCH 8, 1974

## RULES AND REGULATIONS

### Title 40—Protection of the Environment

#### CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

##### SUBCHAPTER C—AIR PROGRAMS

[FRL 391-4]

### 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 transmissionometer 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

## RULES AND REGULATIONS

### 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

\* \* \* \* \*

##### 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.

\* \* \* \* \*

##### MONITORING REQUIREMENTS

Several comments were received with regard to the sections requiring a flow measuring device which has an accuracy of  $\pm 5$  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, "weigh-belts" 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  $\pm 5$  percent accuracy requirement would be easily met, and a search of pertinent literature showed that weighing devices with  $\pm 1$  percent accuracy are commercially available.

\* \* \* \* \*

**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.

FEDERAL REGISTER, VOL. 40, NO. 152—  
—WEDNESDAY, AUGUST 6, 1975

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-5 and 9).

Dated: November 1, 1974.

JOHN QUARLES,  
Acting Administrator.

FEDERAL REGISTER, VOL. 39, NO. 219—  
—TUESDAY, NOVEMBER 12, 1974

## RULES AND REGULATIONS

### 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. 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

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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 reg-

ulations 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, or O<sub>2</sub> 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<sub>2</sub> within the control device. It should be noted that when any fuel is fired directly in the stack gases

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for reheating, the  $F$  and  $F_p$  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  $\pm 5$  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  $120^\circ C$  for most source categories subject to standards of performance. Reasons for selection of  $120^\circ C$  include the following:

a. Filter temperature must be held above  $100^\circ C$  at sources where moist gas streams are present. Below  $100^\circ C$ , condensation can occur with resultant plugging of filters and possible gas/liquid reactions. A temperature of  $120^\circ C$  allows for expected temperature variation within the train, without dropping below  $100^\circ C$ .

b. Matter existing in particulate form at  $120^\circ C$  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  $120^\circ C$  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  $160^\circ C$ ). 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 condensable 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  $120^\circ C$  as compared to about  $150^\circ C$  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 condensable 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  $160^\circ C$ . Since this temperature is attainable at new steam generator stacks, sampling at temperatures above  $160^\circ C$  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.

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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<sub>2</sub> 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<sub>x</sub> continuous monitoring systems capable of measuring only nitric oxide (NO) since the amount of nitrogen dioxide (NO<sub>2</sub>) 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<sub>2</sub>) 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<sub>x</sub> relative to NO in the flue gases and use a factor to adjust the continuous monitoring system emission data (e.g.  $1.03 \times \text{NO} = \text{NO}_x$ ) 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<sub>2</sub> (greater than 90 percent NO) in order to not seriously impair the accuracy of the system due to NO<sub>2</sub> 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<sub>2</sub> concentration entering the converter. Air injection plants must make additional corrections for the diluent air added. Measurement of the inlet SO<sub>2</sub> 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

## RULES AND REGULATIONS

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<sub>2</sub>S and CO monitoring systems. The provisions of § 60.105(a)(3) do not apply to an owner or operator electing to monitor H<sub>2</sub>S. In that case, an H<sub>2</sub>S monitor should not be installed until specific H<sub>2</sub>S 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 [date of publication] 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 capacity that must be reported, has been reserved for the same reasons discussed under fossil fuel-fired steam generators.

(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 con-

tinuous 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<sub>2</sub> or CO<sub>2</sub>) 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.

FEDERAL REGISTER, VOL. 40, NO. 194—

—MONDAY, OCTOBER 6, 1975

# **ENVIRONMENTAL PROTECTION AGENCY**



## **ELECTRIC UTILITY STEAM GENERATING UNITS**

**Proposed Standards of  
Performance and Announcement  
of Public Hearing on Proposed  
Standards**

[6560-01]

# ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 60]

[FRL 967-11]

## STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

### Electric Utility Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

**SUMMARY:** The proposed standards of performance would limit emissions of sulfur dioxide (SO<sub>2</sub>), particulate matter, and nitrogen oxides (NO<sub>x</sub>) 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<sub>2</sub> and NO<sub>x</sub> standards is also proposed. 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 proposal is to require new, modified, and reconstructed electric utility steam generating units to use the best demonstrated systems of continuous emission reduction and to satisfy the requirements of the Clean Air Act Amendments of 1977.

The principal issue associated with this proposal is whether electric utility steam generating units firing low-sulfur-content coal should be required to achieve the same percentage reduction in potential SO<sub>2</sub> emissions as those burning higher sulfur content coal. Resolving this question of full versus partial control is difficult because of the significant environmental, energy, and economic implications associated with each alternative. The Administrator has not made a decision on which of the alternatives should be adopted in the final standard and solicits additional data on these impacts before promulgating the final regulation.

The conference report for the Clean Air Act Amendments of 1977 says in 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.

This proposal sets forth the full, or uniform control alternative and sets forth other alternatives for comment as well. It should be noted that the Clean Air Act provides that new source performance standards apply from the date they are proposed and it would be easier for powerplants 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.

The final decision on the appropriate level of control will be made only after analyses are completed and public comments evaluated. Because the decision will require a careful balancing of environmental, energy, and economic impacts, the Administrator believes that extensive public involvement is essential. Comments on the factual basis for the standards and suggestions on the interpretation of data are actively solicited.

**DATES:** *Comments.* Comments must be received on or before November 20, 1978.

*Public hearing.* A separate notice is published in today's **FEDERAL REGISTER** announcing the time and place of a public hearing on the proposed standards.

**ADDRESSES:** *Comments.* 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, N.C. 27711.

*Background information.* The background information documents (refer to section on studies) for the proposed standards 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.

*Docket.* Docket No. OAQPS-78-1, containing all supporting information used by EPA in developing the proposed 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.

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 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 rule-making process. Along with the statement of basis and purpose of the pro-

mulgated 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)).

### 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:** Summary of proposed standards; rationale; background; applicability; SO<sub>2</sub> standards; particulate matter standards; NO<sub>x</sub> standards; studies; performance testing; and miscellaneous.

### SUMMARY OF PROPOSED STANDARDS

#### APPLICABILITY

The proposed standards would apply to electric utility steam generating units that are capable of firing more than 73 MW (250 million Btu/hour) heat input of fossil fuel and for which construction is commenced after September 18, 1978.

#### SO<sub>2</sub> EMISSIONS

The proposed SO<sub>2</sub> standards would limit SO<sub>2</sub> emissions to 520 ng/J (1.2 lb/million Btu) heat input for solid fuel (except for 3 days per month) and 340 ng/J (0.80 lb/million Btu) for liquid and gaseous fuel (except for 3 days per month). Also, uncontrolled SO<sub>2</sub> emissions from solid, liquid, and gaseous fuel would be required to be reduced by 85 percent. Compliance with the SO<sub>2</sub> emission limitation and percent reduction would be determined on a 24-hour daily basis. The 85-percent requirement would apply at all times except for 3 days per month, when only a 75-percent SO<sub>2</sub> reduction requirement would apply. The percent reduction requirement would not apply if SO<sub>2</sub> emissions into the atmosphere are less than 86 ng/J (0.20 lb/million Btu) heat input.

The percent reduction would be computed on the basis of overall SO<sub>2</sub> removed by all types of SO<sub>2</sub> 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 flyash would also be included in the computation.

#### PARTICULATE MATTER EMISSIONS

The proposed particulate matter emission standard would limit emissions to 13 ng/J (0.030 lb/million Btu) heat input. The proposed opacity standard would limit the opacity of emissions to 20 percent (6-minute average). If an affected facility exhibits

opacity levels higher than 20 percent, while at the same time demonstrating compliance with the particulate matter standard, then a source-specific opacity standard may be established under 40 CFR 60.11(e).

#### NO<sub>x</sub> EMISSIONS

The proposed NO<sub>x</sub> emission standards vary according to fuel characteristics as follows:

(1) 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.

(2) 260 ng/J (0.60 lb/million Btu) heat input from the combustion of bituminous coal.

In addition, separate standards are being proposed for gaseous and liquid fuels not derived from coal, lignite from certain areas, and coal refuse.

#### RATIONALE

##### SO<sub>2</sub> STANDARDS

Under section 111(a) of the Act, a standard of performance 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 is to be given for any cleaning of the fuel, or reduction in pollutant characteristics of the fuel, after mining and prior to combustion.

The 1977 amendments substantially changed the criteria for regulating new powerplants by requiring the application of technological methods of control to minimize SO<sub>2</sub> 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 coals of differing characteristics will not undermine the objectives of the House bill and other Act provisions.

The principal issue to be resolved in this rulemaking is whether a plant burning low-sulfur coal should be required to achieve the same percentage reduction in potential SO<sub>2</sub> emissions as those burning higher sulfur content coals.

Prior to framing alternative SO<sub>2</sub> standards, EPA evaluated control technology in terms of performance,

costs, energy requirements, and environmental impacts. EPA has concluded that the proposed emission limits and control efficiencies are achievable with well-designed, maintained, and operated flue gas desulfurization systems but has not determined whether uniform application of these requirements is necessary to satisfy section 111 of the Act. EPA's final decision on this issue must be based on an assessment of the national, regional, and local environmental (air, water, and solid waste), economic, and energy impacts of both the uniform percentage reduction requirement and the other alternatives under consideration.

Toward this end, EPA performed extensive analyses of the potential impacts associated with each of the alternatives at the national, regional, and plantsite levels. Economic models were used for the purpose of forecasting the nature of the utility industry in future years. Evaluation of the data revealed that the results predicted by the model were very sensitive to such assumptions as the rate of growth predicted for the industry, coal and oil prices, and transportation costs. Forecasts which assume low growth in electricity demand and high oil and rail transportation prices resulted in modeled estimates which show relatively small differences in the impacts of the alternatives at the national level. On the other hand, if assumptions of high growth in demand for electricity are combined with low oil and rail transportation prices, more significant economic, energy, and environmental impacts are predicted.

The Agency believes that it would be inappropriate to make a decision on the choice between the full and partial control alternatives without additional analyses of the modeling results. The model is being refined, with particular emphasis being placed on the assumptions used. Comment on the appropriateness of the selected assumptions and the relative significance of environmental, energy, and economic impacts are invited.

At the plant level, the partial control alternative would result in substantially more SO<sub>2</sub> emissions than full control when low-sulfur coal is fired. For example, a Western plant burning low-sulfur coal could emit as much as four times as much SO<sub>2</sub> under the partial control alternative as under full control. However, there are many plant locations where the cost of mandated emission control equipment can be an important factor in the utility's choice of coal to be fired. If partial control is permitted when low-sulfur coal is burned, the lower capital and operating costs associated with the control equipment may justify a decision to use more expensive low-sulfur coal. The same plant might have

chosen cheaper high-sulfur coal if the same control equipment were required for all coals. In such a case, a partial control approach could result in lower emissions than a full control approach. For example, a 500 MW low-sulfur coal plant with partial control might emit 10,000 tons per year while the same plant burning high-sulfur coal under full control might emit some 15,000 tons per year.

The benefits of such shifts from high- to low-sulfur coal must be compared to the costs associated with foregoing increased local coal production. When considering local coal impacts, it must be noted that coal production will increase over current levels in all areas of the country under all control alternatives. This means local coal production impacts will affect the level of new production rather than displace existing production. The Administrator seeks comment on the relative significance of new coal production versus existing coal production as it pertains to the consideration of coal impacts in the final decision.

The economic impact of the standard can be viewed in a number of ways, depending on the economic measures selected and the manner in which they are used. While the capital and operating costs of control can be shown to be significant in absolute terms (e.g., billions of dollars), they can also be shown to be relatively small when compared to the hundreds of billions of dollars in new capital investment planned by the industry or to the approximately \$100 billion annual revenue requirement projected for 1990. If the impact is considered in terms of monthly cost to the average consumer, the alternatives do not appear to have a major impact. However, when computed as a total cost to an average family over a 30- to 40-year period, the impacts can appear much more significant. In view of this, the Administrator solicits comments on which economic indicators are most appropriate and how the comparisons should be made.

A consideration in establishing the new source performance standards for powerplants is their relationship to the prevention of significant deterioration (PSD) program. Since virtually all new powerplants will have to comply with both the standards of performance and PSD requirements, concern has been expressed that the case-by-case best available control technology review under PSD creates the potential for prolonged public debate as to the adequacy of the control proposed for a given source. The likelihood of such debate, and the associated delays, would increase if a less stringent standard of performance is adopted. Consideration must also be given to the impact that a source complying

with the revised standard of performance will have on the air quality increment. A source with lower emissions will use less of the available increment, thus providing a greater margin for growth. As mentioned above, the impact of this standard can be either to increase or to decrease emission rates for a given plant depending on the selection of the coal to be fired. In view of the above, the Administrator solicits comments as to how much weight should be given to PSD considerations when establishing the final standard of performance requirement.

#### PARTICULATE MATTER STANDARDS

The proposed standards would limit the emissions of particulate matter to 13 ng/J (0.03 lb/million Btu) heat input and would require a 99-percent reduction in uncontrolled emissions from solid fuels and a 70-percent reduction for liquid fuels. No particulate matter control would be necessary for units firing gaseous fuels alone, and thus a percent reduction would not be required. The 20-percent opacity (6-minute average) standard that is currently applicable to steam electric generating units (40 CFR Part 60, Subpart D) would be retained under the proposed standard to insure proper operation and maintenance of the particulate matter control system.

The proposed standards are based on the performance of a well designed and operated baghouse or electrostatic precipitator (ESP). EPA has determined that these control systems are the best adequately demonstrated systems 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).

This determination was reached after analyzing emission test results from steam generators firing both high- and low-sulfur coal and employing either ESP's or baghouses. Although the baghouse data were based on units of less than 44 MW, EPA has concluded that there are no technological barriers that would preclude their application on larger units. In addition, a number of large installations are now under construction, and a 350-MW facility equipped with a baghouse for particulate emission control recently began operation.

EPA considered a standard of 21 ng/J (0.05 lb/million Btu) which could be met by wet particulate matter scrubbers in addition to baghouses and ESPs, but rejected this option because using scrubbers could increase emissions of fine particulate matter. A 21 ng/J standard would result in 60 percent higher emissions which could have an adverse effect on visibility. On the other hand, an advantage to allow-

ing the use of scrubbers is that a single scrubber may be able to control both SO<sub>2</sub> and particulate matter.

It should be noted that there were no plants available for testing at which a well designed ESP or baghouse was followed by an FGD system; thus, the proposed standards are based on emission measurements taken at the particulate matter control device discharge prior to any FGD unit. Since there is the potential for an FGD system to affect particulate emissions, EPA is continuing to assess this situation. Of particular concern is the potential contribution of sulfuric acid mist to the measured particulate matter emissions. This issue is discussed in more detail under the particulate matter standards section of this preamble. EPA solicits comments and available data on this matter.

The proposed limit of 13 ng/J (0.03 lb/million Btu) will effectively preclude the use of ESPs on facilities using low sulfur coal and require baghouse control. DOE and the utility industry believe that baghouse technology has not been demonstrated sufficiently to require its use on utility size facilities. Because of this, DOE recommends that the standard be no less than 21 ng/J (0.05 lb/million Btu) while the industry recommends a standard of 34 ng/J (0.08 lb/million Btu). EPA requests comments on this recommendation as well as on EPA's proposal.

#### NO<sub>x</sub> STANDARDS

The proposed NO<sub>x</sub> standards for different fuels are based on the emission limitations achievable through combustion modification techniques. Combustion modification limits NO<sub>x</sub> formation in the boiler by reducing flame temperatures and by minimizing the availability of oxygen during combustion. The levels to which NO<sub>x</sub> emissions can be reduced with combustion modification depend upon the type of fuel burned, boiler design, and boiler operating practice.

When considering these factors, EPA concluded that a uniform standard could not be applied to all fossil fuels or boiler types. In addition, EPA took into consideration the adverse side effects of low NO<sub>x</sub> operation such as boiler tube wastage. As a result, different requirements were developed for bituminous and subbituminous coals.

The limitations for coal-derived liquid and gaseous fuels and shale oil are based on limits achievable with subbituminous coals. The limitations for liquid and gaseous fuels are the same as those promulgated in 1971 under 40 CFR part 60 subpart D for large steam generators. These requirements were not reexamined since few, if any, new oil- or gas-fired power

plants are expected to be built. The recently promulgated limitations for lignite combustion (43 FR 9276) have been incorporated into these regulations without change because no new data have become available since their promulgation. Similarly, the exemption for combustion of coal refuse has also been retained.

#### BACKGROUND

In December 1971, under section 111 of the Clean Air Act, the Administrator promulgated standards of performance to limit emissions of SO<sub>2</sub>, particulate matter, and NO<sub>x</sub> from new, modified, and reconstructed fossil-fuel-fired steam generators (40 CFR 60.40 et seq.). Since that time, the technology for controlling these emissions has improved, but emissions of SO<sub>2</sub>, particulate matter, and NO<sub>x</sub> continue to be a national problem. In 1976, steam electric generating units contributed 24 percent of the particulate matter, 65 percent of the SO<sub>2</sub>, and 29 percent of the NO<sub>x</sub> emissions on a national basis.

The utility industry is expected to have continued and significant growth; approximately 300 new fossil-fuel-fired power plant boilers are to begin operation within the next 10 years. Associated with utility growth is the continued long-term increase in utility coal consumption from some 650 million tons/year in 1975 to between 1,400 and 1,800 million tons/year in 1990. Under the current performance standards for power plants, national SO<sub>2</sub> emissions are projected to increase approximately 15 to 16 percent between 1975 and 1990.

Impacts will be more dramatic on a regional basis. For example, in the absence of more stringent controls, utility SO<sub>2</sub> emissions are expected to increase tenfold to over 2 million tons by 1990 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<sub>2</sub> standard so as to require a 90 percent reduction in SO<sub>2</sub> emissions from all coal-fired power plants. The petition included information to support the claim that advances in technology since 1971 called for a revision of the standard, and EPA agreed to investigate the matter thoroughly. On January 27, 1977 (42 FR 5121), EPA announced that it had initiated a study to complete the technological, economic, and other documentation needed to determine to what extent the SO<sub>2</sub> 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, require 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 (NAPCTAC) 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 EPA 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 EPA propose the revised standards by August 7, 1978. A consent order was developed and issued by the court requiring the EPA Administrator to (1) deliver the proposal package to the office of the Federal Register by September 12, 1978, and (2) promulgate the final standards within 6 months after proposal.

The purpose of this proposal is to respond to the petition of the Navaho Tribe and Sierra Club, and to initiate the rulemaking required under section 111(b)(6) of the Act.

#### APPLICABILITY

The proposed standards would apply to all electric utility steam generating units (1) capable of firing more than 73 MW (250 million Btu/per hour) heat input of fossil fuel (approximately 25 MW of electrical energy output) and (2) for which construction is commenced after September 18, 1978.

On December 23, 1971, EPA 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 proposed standards will not apply to electric utility steam generating units originally subject to those standards (subpart D) unless the affected facilities 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 power distribution system and is constructed for the purpose of selling for use by the general public

more than one-third of its maximum electrical generating capacity. Any steam that could be sold to produce electrical power for sale is also included when determining applicability of the standard.

#### INDUSTRIAL FACILITIES

Industrial steam electric generating units with heat input above 73 MW that are constructed for the purpose of selling more than one-third of their maximum electrical generation capacity (or steam generating capacity used to produce electricity for sale) would be covered under the proposed standards. Industrial steam generating units with a heat input above 73 MW that produce only steam or that were constructed for the purpose of selling less than one-third of their electric generation capacity are not covered by the proposed standards, but will continue to be covered under subpart D.

#### COGENERATION

Electric cogeneration units (steam generating units that would produce steam used for electric generation and process heat) would be considered electric utility steam generating units if they: (1) Were capable of combusting more than 73 MW of fossil fuel and (2) would be physically connected to a power distribution system for the purpose of selling for use by the general public more than one-third of their maximum electrical generating capacity. Cogeneration facilities that would produce power only for "in-house" industrial use would be considered industrial boilers and would be covered under subpart D if applicable.

#### RESOURCE RECOVERY UNITS

Steam electric generating units that combust nonfossil fuels such as wood residue, sewage sludge, waste material, or municipal refuse (either alone or in combination with fossil fuel) would only be covered by the proposed standards if the steam generating unit is capable of firing more than 73 MW of fossil fuel. If only municipal refuse were fired and the unit was not capable of being fired with more than 73 MW of fossil fuel, the unit would be considered an incinerator and the standards under subpart E would apply. Similarly, the standards under subpart O for sewage treatment plants would apply if only sewage sludge were burned.

#### COMBINED-CYCLE GAS TURBINES

The proposed standards would cover boiler emissions from electric utility combined-cycle gas turbines that are capable of being fired with more than 73 MW (250 million Btu-hour) heat input of fossil fuel in the steam generator, and where the unit is constructed

for the purpose of selling more than one-third of its electrical output capacity to the general public. Electric utility combined-cycle gas turbines that use only turbine exhaust gas to heat a steam generator (waste heat boiler) or that are not capable of being fired with more than 73 MW of fossil fuel in the steam generator would not be covered by the proposed standards.

#### ISSUES ON APPLICABILITY

**Noncontinental areas.** There are several island areas that would be affected by the proposed standards. Because of the unique characteristics of these areas, it is expected that all of their future power plants will use oil rather than coal. The issue is whether these new oil-fired units should be subject to the proposed 85 percent reduction, which would effectively require the use of PGD or equivalent systems, or to allow the use of low sulfur oil. After considering the costs of requiring PGD systems in light of the limited land area available for sludge disposal, EPA has decided to propose an exemption for these facilities from the 85 percent reduction requirement. They would have to comply with the proposed SO<sub>2</sub> limit for oil-fired facilities of 340 ng/J (0.80 lb/million Btu) as well as all other proposed standards (see section 4.4 of EPA 450/3-78-007a-1).

**Anthracite coal and Alaskan coal.** The proposed standards would cover facilities combusting low sulfur anthracite coal or Alaskan coal in the same manner as all other coals.

EPA realizes, however, there are arguments in favor of allowing less stringent standards because of unique factors for both coals.

With respect to Alaskan coal, it is argued that the unique climatic conditions in Alaska coupled with the very low sulfur content of the coal makes it unreasonable to apply the same percent reduction requirement for SO<sub>2</sub> emissions to power plants located in that State. Anthracite is also low in sulfur content, but it is more expensive to produce than other locally available coals. In view of this, proponents of anthracite argue that if control cost were reduced through a less stringent standard, anthracite could then compete with locally available high sulfur content bituminous coal (see section 4.7.3 of EPA 450/2-78-007a-1).

**Emerging technologies.** Various groups expressed concern that if the proposed standards were rigidly applied, the development of new and promising technologies might be discouraged. They suggested that the innovative technology waiver provisions under the Clean Air Act Amendments of 1977 are not adequate to encourage certain capital-intensive, front-end

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control technologies. Under the innovative technology waiver provisions (section 111(j) of the Act) the Administrator may grant waivers for a period of up to 7 years from the date of issuance of the 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. For most front-end control technologies, modification or retrofit may be economically unreasonable.

To mitigate the potential impact on emerging front-end technologies, EPA proposes to establish slightly less stringent requirements for initial full-scale demonstration plants. This should insure that these standards do not preclude the development of new front-end technologies and should compensate for problems that may arise when applying them to commercial-scale facilities. The 85 percent SO<sub>2</sub> control requirement and the 210-ng/J NO<sub>x</sub> standard will provide developers of new technologies a clear environmental control objective for commercial facilities. However, if the Administrator subsequently finds that a given emerging technology (taking into consideration all areas of environmental impact, including air, water, solid waste, toxics, and land use) offers superior overall environmental performance, alternative standards would then be established by the Administrator.

Under the proposal, the Administrator (in consultation with the Department of Energy) would issue commercial demonstration permits for the first three full scale demonstration facilities of each of the technologies listed in the following table. These technologies have been shown to have the potential to achieve the standards established for commercial facilities. Under such permits, an 80 percent SO<sub>2</sub> control level (24-hour average) or a 300 ng/J (0.70 lb/million Btu) NO<sub>x</sub> emission limitation for liquid fuel derived from bituminous coals would be established. If the Administrator (in consultation with the Department of Energy) finds that additional demonstration of a given technology is necessary, additional permits may be issued. No more than 15,000 MW equivalent electrical capacity would be allocated for the purpose of commercial demonstrations under this proposal. This capacity would be allocated as follows:

| Technology                              | Pollutant Equivalent | MW                  |
|-----------------------------------------|----------------------|---------------------|
|                                         |                      | electrical capacity |
| Solvent-refined coal.....               | SO <sub>2</sub>      | 6,000-10,000        |
| Fluidized bed combustion (atmospheric). | SO <sub>2</sub>      | 400-3,000           |
| Fluidized bed combustion (pressurized). | SO <sub>2</sub>      | 200-1,200           |
| Coal liquefaction.....                  | NO <sub>x</sub>      | 750-10,000          |

The capacity is presented in ranges because of uncertainty as to the amount that will be required for any one technology. This use of ranges should not be construed to mean that more than 15,000 MW would be allocated for purposes of commercial demonstration permits.

It should be noted that these permits would only apply to the application of this standard and would not supercede the new source review procedures and prevention of significant deterioration requirements under section 110 of the Act.

Finally, concern has been expressed as to whether emerging technologies should be required to comply with the proposed particulate standard. Since this concern is based on the same arguments that have been offered in regard to conventional technologies, consideration of special provisions will be tied to the final decision on the particulate emission limitation.

**Modifications.** The question has been raised whether the use of shale oil coal-based fuels such as coal/oil mixtures or solvent-refined coal in a boiler originally designed for oil firing is considered a modification under 40 CFR 60.14(c). In response, EPA proposes that shifting an existing oil-fired steam generator to coal/oil mixtures, shale oil, or coal-derived fuels, would not be considered a modification and the facility would not be subject to the proposed standards.

SO<sub>2</sub> STANDARDS

**General Requirements.** The proposed standards for SO<sub>2</sub> emissions would require:

1. Reduction of potential SO<sub>2</sub> emissions for solid, liquid, and gaseous fuels by 85 percent (24-hour average control efficiency) except for 3 days per month when no less than 75 percent is allowed.

2. Maximum allowable emissions from solid fuel of 520 ng/J (1.2 lb/million Btu) heat input 24-hour average except for the 3 days per month when the 75 percent is allowed.

3. Maximum allowable emissions from liquid or gaseous fuels of 340 ng/J (0.80 lb/million Btu) heat input 24-hour average except for 3 days per month.

4. Maximum control level of 86 ng/J (0.20 lb/million Btu) heat input 24-hour average.

## DISCUSSION

The proposed standards are based on emission levels and the percentage reduction achievable with a well designed, operated, and maintained flue gas desulfurization (FGD) system. EPA believes the following types of FGD systems are capable of achieving the proposed standards: lime, limestone, Wellman-Lord, magnesium oxide, and double alkali. In determining that FGD is the best system of continuous emission reduction that has been adequately demonstrated for removal of SO<sub>2</sub>, EPA assessed the costs of achieving the proposed standards and the nonair quality health and environmental impacts and energy requirements. Although the proposed standards are based on the performance of FGD systems, the use of other systems should not be discouraged. In this regard, a number of emerging technologies show promise.

The proposed percentage reduction requirement would apply to the combustion of all fossil fuels unless the emission level of 86 ng/J (0.20 lb/million Btu) is constantly attained (24-hour average basis). In effect, this means that all coal-fired and residual-oil-fired plants would be required to install FGD or equivalent SO<sub>2</sub> emission control systems. On the other hand, the emission level of 86 ng/J would permit certain clean fuels, such as wood waste, to be burned without FGD or at a very low percentage of reduction.

The emission limitations of 520 ng/J (1.2 lb/million Btu) for solid fuels and 340 ng/J (0.80 lb/million Btu) for liquid and gaseous fuels would place a maximum limit on SO<sub>2</sub> emissions regardless of percentage of SO<sub>2</sub> reduction attained and thus restrict the amount of sulfur in the fuel fired.

In determining that FGD systems were adequately demonstrated and that they could attain the proposed limitations, EPA has conducted a number of studies either directly or through consultants. To evaluate the relative performance of FGD systems, EPA has conducted tests at various sites. Several absorber designs and absorbents were tested at the Shawnee 10-MW test facility, emission tests were performed at various full-scale operations, and performance results from other test facilities and scrubber installations were surveyed, both in the United States and Japan. A detailed summary of the results from these studies is provided in section 4.2 of the supplement to the Background Information document for SO<sub>2</sub> (EPA 450/2-78-007a-1). In addition, all of the study reports are available in the

docket for review (see listing set forth later in this preamble).

#### PERCENTAGE REDUCTION REQUIREMENT

In establishing the percentage reduction requirement for potential SO<sub>2</sub> emissions for solid, liquid, and gaseous fuels, EPA considered the SO<sub>2</sub> removal efficiency of prototype, pilot-scale, and commercial-scale FGD systems. EPA's considerations included measured variability of percentage reduction, effects of scrubber and coal sulfur variability on performance, effects of a spare module on scrubber reliability, and effects of design changes and maintenance practices on scrubber reliability.

To establish the variation of FGD system removal efficiency and the effects of varying sulfur content of coal on measured 24-hour-average SO<sub>2</sub> removals, EPA obtained continuous monitoring data from the Cane Run and Bruce Mansfield powerplants. These data were analyzed to establish the geometric standard deviations. Based on these analyses, EPA projected the mean SO<sub>2</sub> removal needed to comply with the proposed percentage reduction requirement. At the 99.99 percent confidence level, EPA concluded that an FGD system that could achieve a 92 percent long-term (30 days or more) mean SO<sub>2</sub> removal would comply with the proposed 85 percent (24-hour average) requirement.

With respect to long-term SO<sub>2</sub> removal efficiency, EPA has concluded that with certain practical changes in design, operation, and maintenance practices, lime/limestone FGD systems can achieve long-term SO<sub>2</sub> removal of 92 percent. FGD technologies employing more reactive absorbents such as magnesium oxide, additive magnesium-oxide-enriched lime, and sodium-based liquors can achieve SO<sub>2</sub> removal levels of greater than 92 percent. For a more detailed discussion of these findings, please refer to section 4.2 of EPA 450/2-78-007a-1.

#### FGD AVAILABILITY

With respect to conditions that may affect FGD availability, EPA has investigated such problems as:

1. Formation of scale in the absorber and associated equipment in lime and limestone systems leading to plugging and reduced capacity.
2. Plugging of mist eliminators, lines, and some types of absorbers.
3. Failure of ancillary equipment such as pumps, piping, pH-sensing equipment, reheaters, centrifuges, fans, and duct and stack linings.
4. Inadequate absorbent make-up preparation.

EPA has concluded that these problems can and have been solved through the improved design of com-

ponents, proper selection of construction materials, appropriate sparing, good operating practices, and good maintenance. As a result, the availability of full-scale scrubbing facilities has increased steadily. (See EPA 600/7-78-032b.) When determining FGD availability, one must recognize that FGD systems are composed of FGD modules, each of which is a separate scrubbing system. Because FGD modules are not generally manufactured in sizes over 125-MW capacity, large powerplants use multiple FGD modules in parallel. When FGD modules, even those averaging 90 percent availability, are integrated into an FGD system, the probability that all modules in the system will be simultaneously available diminishes in proportion to the number of modules; therefore, spare FGD modules will be needed in most instances. Such spares were included in EPA's estimates of FGD costs. Even when high FGD module availabilities are attained, the FGD module will not be in service some of the time because of regularly scheduled maintenance operations or repairs needed to restore loss of scrubbing efficiency. Although the amount of time for such maintenance can be considerable (even continuous), there should be little adverse impact on plant operation. With spares, a module can be rotated out of operation for maintenance even at full electrical load conditions. Several plants now in operation employ such a system. At reduced electrical loads, all FGD modules will not be needed for SO<sub>2</sub> control. Periodically, the entire plant is taken out of service for servicing non-FGD system related components providing an opportunity for scheduled FGD maintenance.

EPA acknowledges that even with a good maintenance program and use of spare FGD modules it may not be possible to maintain complete FGD system control for a portion of a plant's operating hours. At these times, the proposed standards would require that the electric generating load be shifted to an alternative electric generating plant. This procedure is necessary to prevent bypassing of uncontrolled SO<sub>2</sub> emissions to the atmosphere.

Load shifting is normally feasible, but it will not be possible when emergency conditions exist. Emergency conditions are considered to be periods when a powerplant and other electrical generating equipment owned by the associated utility company are being operated at full operating capacity less the capacity equal to the largest single unit in the system. Under emergency conditions, the proposed standards would allow flue gas to be bypassed around an inoperable FGD module provided the facility is

equipped with at least one spare module. The proposed standards would not require plants having capacity of less than 125 MW to have a spare module. Bypassing an FGD unit except under emergency conditions would be a violation of the standards.

The emergency condition provisions are necessary to maintain the electric utility's capability to meet electric demand when excess generating reserves are not available. A minimal amount of spinning reserves must be kept separate from the load shifting procedures to prevent "blackouts." Please refer to section 4.6 of EPA 450/2-78-007a-1 for a more detailed discussion of this matter.

#### ENVIRONMENTAL IMPACTS

A major consideration with respect to nonregenerable FGD systems is the disposal of sludge and contamination from wastewater; therefore, EPA had its consultants examine these potential problems in detail.

With respect to sludge disposal, the consultant examined a number of parameters including the quantification of solid wastes that would be generated by different regulatory options, plant sizes, coal sulfur contents, and scrubbing processes. In addition, untreated wastes were characterized by effects of scrubbing process variables on sludge chemistry, trace element content, and physical and chemical properties. Finally, the environmental impacts and costs of various disposal processes and practices were assessed. ("Controlling SO<sub>2</sub> Emissions from Coal-Fired Steam Electric Generators: Solid Waste Impact," EPA 600/7-78-044.)

From a companion analysis ("Review of New Source Standards for SO<sub>2</sub> Emissions from Coal-Fired Utility Boilers," vol. 1, sec. 3), it is estimated that under the 85-percent reduction requirement the quantity of sludge generated will increase from some 12 million metric tons dry basis (current standard) to some 55 million metric tons dry basis in 1995. These figures are conservative since they assume a high-growth rate in electrical demand (5.8 percent through 1985, and 5.5 percent thereafter). The quantity of sludge generated would be less under regulatory options that do not require a uniform application of the 85-percent reduction requirement.

To estimate the cost of sludge disposal, EPA assumed that dewatered sludge would be fixed with lime and fly ash and be impounded in a clay-lined pond. Based on this assumption, EPA estimates that the cost of disposal would be some \$19 per dry metric ton including land costs.

In addition, a field disposal study, which has been underway for 3 years at TVA's Shawnee powerplant site,

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has not revealed any significant problems from impoundment of treated FGD wastes.

EPA has concluded from these studies that sludge can be disposed of in an environmentally sound manner at reasonable costs. EPA will continue to evaluate the costs and effectiveness of alternative disposal methods as part of the economic analyses to be conducted during the proposal period. Comments on alternative control methods are invited.

With respect to the potential water pollution impact, EPA's consultant examined alternative standards in terms of their effects on the quality and quantity of powerplant waste-water effluents, and the amount of water consumption. In addition, alternative SO<sub>2</sub> control systems were examined relative to their impact on the above. The potential environmental effects of SO<sub>2</sub> control on effluents were also examined, and alternative treatment processes were evaluated.

The water pollution impact report "Controlling SO<sub>2</sub> Emissions from Coal-Fired Steam Electric Generators: Water Pollution Impact," EPA 600/7-78-045, concluded that in the aggregate the volume and quality of waste streams from SO<sub>2</sub> control systems are affected very little by alternative standards and that all effluent streams can be treated to acceptable levels using proven, commercially available technologies. Similarly, a more stringent standard would have little effect on water demand when compared to total plant consumptive water use.

## ALTERNATIVE TECHNOLOGY

A potential alternative to wet FGD systems is dry SO<sub>2</sub> scrubbing. One of the more effective designs incorporates the use of a spray dryer and baghouse. In this system a spray dryer (similar to a wet SO<sub>2</sub> scrubber) is used with lime, soda ash, or other reactants to scrub SO<sub>2</sub> from the flue gases. Because of the minimal use of water in the spray dryer (by design), no additional reheating is required. Following the spray dryer, a baghouse is used to collect all particulate matter (including SO<sub>2</sub> reactants).

Spray drying has been tested at pilot plants, and it may be capable of achieving 85 percent removal with lime, soda ash, and other reactants. Due to cost considerations, the system is principally limited to coals with less than 1.5-percent sulfur if lime is used. Full-sized spray-drying units for powerplant application have been ordered and are expected to begin operation in the early 1980's. (Refer to sec. 4.3 of EPA 450/2-78-007a-1.)

In addition, a combination of physical cleaning of the fuel in conjunction with FGD systems may be a viable

option for reducing SO<sub>2</sub>, depending on the particular characteristics of the coal being used.

## MAXIMUM ALLOWABLE EMISSION LIMITATION

In selecting the proposed maximum allowable emission limitation, EPA had to take into consideration two primary factors: FGD performance and the impact of the limitation on high-sulfur coal reserves. In effect, FGD performance determines the maximum sulfur content of coals that can be fired in achieving compliance with the maximum allowable emission limitation. To estimate coal sulfur content which can be used, EPA projected SO<sub>2</sub> emissions based upon minimum FGD system performance (i.e., 75 percent SO<sub>2</sub> removal 3 days per month) and maximum daily average sulfur content. Two alternative maximum allowable emission levels were considered: (a) 520 ng/J with three exemptions per month that would be coincident with the proposed percentage reduction requirement, and (b) 520 ng/J with no exemptions.

An analysis of national and regional coal production in 1990 was performed for each option. There would be no significant differences in total national production with either option. The analysis included use of cleaned, midwestern coal when coal cleaning would be necessary to attain compliance with the limitation. Sufficient reserves would be available to satisfy national demand with either option. However, on a regional basis a limitation without exemptions could have the potential of dislocating some coal production in the Midwest.

Under either option, midwestern coal production would increase to about 300 million tons; however, the use of some coal reserves in this area would be restricted by the limitation without exemptions. In the States of Ohio, Illinois, and in western Kentucky, 60 or more percent of reserves might be restricted even if coal cleaning were used.

On the other hand, this analysis may overstate the potential impacts since coal mixing or other methods of reducing the maximum daily average coal sulfur content were not fully considered. In view of this, the Agency will continue to examine the need for exemptions and the appropriateness of more stringent maximum emission levels such as 410 ng/J (1.0 lb/million Btu) or 340 ng/J (0.80 lb/million Btu) during the comment period. (See section 4.7.1 of EPA 450/2-78-007a-1 for a more detailed discussion.)

Based on our present estimates of the potential impact upon midwestern coal reserves and production, EPA has proposed that the maximum allowable emission limitation should have a 3-

day exemption coincident with the 3 days of 75-percent control in the percent reduction standard. However, the Agency specifically requests comments on the level of the emission limit and the appropriateness of the 3-day exemption.

## MAXIMUM CONTROL LEVEL

Under the proposed SO<sub>2</sub> standard, a maximum control level would be established. Compliance with that control level would constitute compliance with the percentage reduction requirement. In developing the proposed standard, EPA has considered two alternatives. The first would establish the level of 86 ng/J (0.20 lb/million Btu). The second would establish a higher level. Values from 215 ng/J (0.50 lb/million Btu) to 340 ng/J (0.80 lb/million Btu) have been considered.

In essence, these options focus on the question of whether a powerplant burning low-sulfur coal should be required to achieve the same percentage reduction as those burning high-sulfur coal. The emission level of 86 ng/J would require virtually all coal-fired plants to reduce potential emissions by 85 percent. In addition, it would require the installation of FGD systems on oil-fired powerplants. Therefore, this option is commonly referred to as full scrubbing or full control. On the other hand, an emission level in the range of 215-340 ng/J would permit plants firing low-sulfur coal to reduce their emissions by less than 85 percent, hence the term partial scrubbing.

Proponents of partial scrubbing have argued that adoption of a limitation in the range of 215-340 ng/J would reduce scrubber costs and permit bypassing of a portion of the flue gas and thus alleviate the need for plume reheat and associated energy costs, since low-sulfur coal inherently emits less SO<sub>2</sub>. Proponents of partial scrubbing maintain that these benefits can be obtained by partial scrubbing without a significant increase in emissions nationally. Finally, it is argued that since coal-fired units would be cheaper to build and operate if partial scrubbing were allowed, less dependence would be placed on existing oil-fired units and turbines, and a significant saving of oil would be realized.

On the other hand, proponents of full control have maintained that plants firing low-sulfur coal should be subject to the same reduction requirement as those burning high-sulfur coal. They argue that the statutory requirements and legislative history of section 111 of the Clean Air Act Amendments of 1977 require a uniform percentage reduction requirement. They also point out that applying full scrubbing to low-sulfur coal is technologically less demanding and

less expensive than applying full scrubbing to high-sulfur coal and that emissions from a plant burning low-sulfur coal would be up to four times greater under partial scrubbing than under full control. Finally, it is argued that adoption of full control will tend to promote the use of locally available, higher sulfur content coals, particularly in the Midwest.

#### ALTERNATIVE SO<sub>2</sub> STANDARDS

The following alternative standards for SO<sub>2</sub> have been suggested by DOE:

1. Eighty-five percent reduction of potential SO<sub>2</sub> emissions during each calendar month.
2. A maximum control level of 340 ng/J (0.80 lb SO<sub>2</sub>/million Btu), not to be exceeded during any 24-hour period.
3. A minimum of 33-percent reduction of potential SO<sub>2</sub> emissions. The alternative standards would have the following operational characteristics:

**Monthly averaging.** There would be no daily restriction on the percent reduction in potential SO<sub>2</sub> emissions. The requirement would be that the total sulfur emissions summed over each calendar month be no more than 15 percent of the total sulfur content of the coal consumed. There would be no restriction on bypassing some or all of the flue gas, so long as the monthly percent reduction requirement is met. If the monthly requirement is not met, enforcement penalties would be applied on the basis of the number of individual 24-hour periods during which the percent reduction was less than 85 percent.

**Maximum control level of 340 ng/J (0.80 lb SO<sub>2</sub>/million Btu).** Under this alternative, a sliding-scale-percent reduction would be required; the full 85-percent reduction would be required only when high-sulfur coals were used. Only the minimum percent reduction requirement would be enforced for 24-hour periods when SO<sub>2</sub> emissions would be 340 ng/J or less. Any 24-hour period when emissions are greater than 340 ng/J and reduction is less than 85 percent will be a violation of the percent reduction requirement. There would be no waivers or exemption for this daily requirement.

**Minimum percent reduction requirement of 33 percent.** Regardless of whether the resulting emissions would be lower than the 340 ng/J (0.80 lb/million Btu) emissions requirement, 33-percent reduction in potential SO<sub>2</sub> emissions would be required. This would assure that continuous emissions reduction technology is applied to all coals, including those with the lowest naturally occurring sulfur content.

In addition to the DOE proposal, the utility industry, through the Utility Air Regulatory Group (UARG), has

also suggested an alternative SO<sub>2</sub> standard. The industry proposal contemplates a sliding scale percentage production standard for sulfur-dioxide emissions under which the required percent reduction declines as sulfur content in the coal declines. Under the industry proposal, there would be a ceiling of 1.2 pounds of sulfur dioxide and the required percent reduction would range between 85-percent removal on a coal with uncontrolled emissions<sup>1</sup> of 8 pounds to 20-percent removal on coals with uncontrolled emissions of 1 pound or less. Specifically, for coals with uncontrolled emissions of 5.0 pounds of sulfur dioxide or greater, the constraining emissions limit would be 1.2 pounds of sulfur dioxide. For coals with uncontrolled sulfur-dioxide emissions of 5 pounds of sulfur dioxide, percent removal would be 76 percent and, in the range between 5 pounds and 4 pounds of uncontrolled emissions, percent removal would decline by 0.1 percentage point for each 0.1-pound decrease in uncontrolled emissions. For coals with uncontrolled emissions of 4 pounds of sulfur dioxide, percent removal would be 75 percent and, between 4 pounds and 3 pounds of uncontrolled emissions, percent removal would decline by 0.9 percentage point for each 0.1 pound decrease in uncontrolled emissions. For coals with 3 pounds of uncontrolled emissions, percent removal would be 66 percent, and between 3 pounds of sulfur dioxide and 2 pounds of sulfur dioxide, percent removal would decline by 1.3 percentage points for each 0.1-pound decrease in uncontrolled emissions. At 2 pounds of uncontrolled emissions percent removal would be 53 percent, and between 2 pounds and 1 pound of uncontrolled emissions, percent removal would decline by 3.3 percentage points for each 0.1 pound decline in uncontrolled emissions. For coals with 1 pound or less of uncontrolled emissions percent removal would be 20 percent.

Compliance with these sulfur-dioxide standards would be determined on a 30-day average. Industry has also recommended that consideration be given to establishing an emission ceiling of 1.5 pounds for coal with uncontrolled emissions over 8 pounds.

Comments on these alternative standards are invited.

#### ANALYSES OF ALTERNATIVES

In order to determine the appropriate form and level of control for the

<sup>1</sup>Uncontrolled emissions of sulfur dioxide are defined as twice the sulfur content of the coal measured in pounds per million Btu. For the purposes of this standard, sulfur content of the coal can be measured at the plant for unwashed coals and at the mine prior to washing, for washed coals. In calculating percent removal, sulfur content of the flue gas as it leaves the stack is compared with the uncontrolled emissions of the coal.

proposed standards, EPA has performed extensive analyses of the potential national impacts associated with the alternative standards. The Agency 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 were a preliminary analysis completed in April 1978 and a revised assessment completed in August 1978. While these analyses are preliminary and subject to change, the issues examined and the results obtained are summarized in this section and in the following tables. Further details of the analyses can be found in "Background Information for Proposed SO<sub>2</sub> Emission Standards-Supplement," EPA 450/2-78-007a-1.

**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 Agency is also evaluating the significance of waste products generated by the control technologies and their environmental impacts.

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 average monthly residential bills. The alternatives were also examined in terms of cost per ton of SO<sub>2</sub> 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 by geographic region and consumption by region. The amount of western coal shipped to the Midwest and East was also estimated. In addition, utility consumption of oil and 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 decisionmaking 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 powerplant 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 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. Comments are solicited regarding the use of a cost optimization model to simulate utility decisions.

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 EPA analyses are shown in table 1 and the significance of these parameters is summarized below. Comments are solicited regarding the assumptions used.

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 April analysis used a relatively high-growth rate consistent with last year's national energy policy

studies. The August analysis used a lower growth projection which is more in line with current estimates of demand growth.

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. The assumptions used in the EPA analyses assume high (April) and moderate (August) growth in nuclear capacity.

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 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. The model does not incorporate the Agency's PSD regulations or forthcoming requirements to protect and enhance visibility. These requirements may be important factors for new powerplants.

*Summary of results.* The results of the EPA analyses which were completed in April and August 1978 are presented in tables 2 through 8 and discussed below. Four alternative standards were evaluated. Each of the options presented includes 85-percent control of inlet SO<sub>2</sub> (24-hour average), except for 3 days per month, a maximum SO<sub>2</sub> emission limit of 520 ng/J (1.2 lb/million Btu) except for 3 days per month, a particulate matter standard of 13 ng/J (0.03 lb/million Btu), and the proposed NO<sub>x</sub> standards. The partial control options in the tables represent alternative levels for the

maximum control level required on a 24-hour basis.

The projected SO<sub>2</sub> emissions from utility boilers are shown by plant type and geographic region in tables 2 through 5. Table 2 details the 1990 national SO<sub>2</sub> emissions resulting from different plant types and age groups. As is expected, the proposed standards result in a significant reduction of SO<sub>2</sub> emissions as compared to the current standards. This reduction ranges from 10 to 12 percent depending on the alternative examined and the assumptions used. The emissions from new plants directly affected by the standards are reduced by up to 73 percent. However, the model predicts that the proposed standards will delay the construction of new plants (note the total coal capacity changes) causing existing coal- and oil-fired plants to be utilized more than they would have been without the proposed standards. This causes an increase in emissions from existing plants which offsets part of the reduction achieved by new plants. As discussed above, this shift in capacity utilized is predicted by the costs minimization model as a result of increased pollution control cost for new coal-fired plants. This shift in the generation mix has important implications for the decisionmaking process. For example, if a national energy policy phases out oil use for electric power generation, then the April study's prediction (table 6) of increased oil use in 1990 (over 1975 levels) will not be allowed to occur. With such a policy, oil consumption impacts would be similar to those shown for the August analysis in table 6.

A summary of the projected 1990 regional SO<sub>2</sub> emissions under the alternative control levels is shown in table 3. The combined emissions in the East and Midwest are reduced about 7 percent as compared to predictions under the current standards. These emissions are not affected greatly by the various control options, although there is a slight increase shown under the 340 ng/J (0.80 lb/million Btu) option in the April analysis. The combined emissions in the west south-central and west regions show a greater variation on a percentage basis. In the analysis, the full control and 210 ng/J (0.50 lb/million Btu) options both result in a 36-percent reduction from emission levels under the current standards, while the 340 ng/J (0.80 lb/million Btu) option results in a 28-percent decrease.

Regional emissions from the new plants directly affected by the proposed standards are shown for the years 1990 and 1995 in tables 4 and 5. These tables also project the coal consumption and emission factors (million tons of SO<sub>2</sub> per quadrillion Btu) for

the new plants. The latter figures are shown to illustrate the effect of changes in the amount of new capacity and variations in the utilization of the new capacity. As noted above, the 1990 emissions from new plants drop dramatically under the proposed standards to a level only about one-third that which would result under the current standards. This emission reduction is due in part to lower emission factors and in part to reduced coal consumption predicted by the model. Coal consumption in the East is virtually unchanged, but in the Midwest coal consumption in new plants drops by one-third as a result of the proposed standards. In the west south-central and west regions coal consumption drops 5 to 10 percent which is about the same as the decline in national coal consumption at new plants. The reduced coal consumption in new plants results from a delay in new plant construction due to the increased cost of generation from new coal plants. Reduced coal consumption by new plants means a shift to more coal and oil burned in existing plants or new turbines, and this causes the increase in emissions from existing and oil-fired plants which was mentioned earlier. Table 5 shows that in 1995 the emission reduction due to the proposed standards is still of the same magnitude as the 1990 reduction. Also, since coal capacity is similar under all options by 1995, the coal consumption impact of the proposed standards is less pronounced. Changes in coal consumption in 1995 are almost entirely due to variations in the utilization of the new plants.

Table 6 illustrates the effect of the proposed standards on 1990 national coal production, western coal shipped east, and utility oil and gas consumption. This table shows some large differences between the two analyses which are caused by different model assumptions. For example, in the model, higher oil prices decrease oil demand and increase coal use. Increasing transportation costs increases the delivered price of western coal and reduces demand. These two factors along with the lower growth rate account for most of the difference in fuel use estimates between the April and August results. However, the conclusions drawn from the analyses are similar. For example, in terms of coal production, both analyses show that total production will increase in all regions of the country as compared to 1975 levels.

Compared to production under the current standards, the April analysis predicts an increase in eastern coal production under all but the 340 ng/J (0.80 lb/million Btu) option. Midwestern production increases under all options, and western production de-

creases under all but the 340 ng/J (0.80 lb/million Btu) option. Western coal shipped east is lower under all options than under the current standard, but is still 14 to 20 times higher than 1975 levels. Finally, the April analysis projects that oil consumption by utilities would be increased by the proposed standards. The increase varies from 300,000 barrels per day for the full control option to 100,000 barrels per day for the 210 ng/J (0.50 lb/million Btu) and 340 ng/J (0.80 lb/million Btu) options.

The August figures predict a smaller increase in 1990 eastern coal production than would be expected under the current standards. Midwestern production increases by 15 to 43 million tons and western production decreases up to 56 million tons. The amount of western coal shipped east is reduced by 30 million tons by both full control and 210 ng/J (0.50 lb/million Btu) options, and is essentially unchanged by the higher options. Due to the high assumed oil price, oil consumption is reduced from current levels, but the 1990 difference between the options and the current standards is still an increase of 200,000 to 300,000 barrels per day. This increased oil consumption results from the predicted shift toward existing oil-fired plants and turbines as a result of higher pollution control costs for new coal plants. Table 8 shows that as high oil prices are assumed (August analysis), there is no difference in 1995 oil consumption among the options. Finally, the DOI/DOE coal leasing study (see "Other Studies") shows a difference of about 50,000 barrels per day in 1990 between full and partial scrubbing.

The economic effects of the proposed standards are shown in table 7 for 1990. Utility capital expenditures between 1979 and 1990 increase under all options as compared to the \$500 to \$750 billion estimated to be required in the absence of a change in the standard. The capital estimates in tables 7 and 8 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 capacity is to be 10 GW to 15 GW greater under the partial control option, and the cost of this extra capacity makes the total utility capital expenditures higher under the 210 ng/J (0.50 lb/million Btu) and 340 ng/J (0.80 lb/million Btu) options, even though pollution control capital is lower than under the full control option.

Annualized cost includes a levelized capital charge, 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 varies, depending on the assumptions modeled, from \$300 million to \$2 billion or a 1- to 2-percent increase over the \$90 to \$100 billion.

The average monthly residential electric bill is predicted to increase only slightly by any of the options, up to a maximum 2-percent increase shown for full control in the April analysis. The large total increase in the monthly bill over 1975 levels is due in large part to a more than 50-percent 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 average monthly bill while the remainder of the cost increase is due to capacity expansion and general cost escalations.

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. Therefore, due to changes in the pattern of expenditures, the selection of the specific year examined has an impact on the costs shown. For example, the August analysis shows slightly higher cost in 1990 for the partial control options as compared to full control. This is due to the larger amount of new capacity and the higher associated capital costs under these options. By 1995, the amount of new coal capacity under each option has approximately equalized, and the estimates show full control to be most expensive but by only 12 cents a month over the average bill under the 340 ng/J (0.80 lb/million Btu) option (table 8).

The incremental costs per ton of SO<sub>2</sub> removal are also shown in table 7. 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<sub>2</sub> 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 \$260 per ton on high-sulfur coal to \$1,600 per ton on low-sulfur coal. The partial scrubbing range is from \$900 per ton on low-sulfur coal to \$2,000 per ton on very low sulfur coal.

The economic analysis also estimated the present value cost in order to facilitate comparison of the options by

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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. Two types of present value costs have been estimated in the analysis.

First, an estimate was made of the present value of costs which will be faced by the consumers. Essentially, this represents the present value of utility revenue requirements. This calculation for the August results shows a 1990 present value of \$26 billion for the full control option and \$15 billion for the 340 ng/J (0.80 lb/million Btu) option as compared to the current standards.

Second, an "economic" or "real resource" present value was estimated. Real resource present value is designed to measure the level of national resources committed to the standards. In computing this resource commitment, construction costs, labor costs, and other resource costs were considered, but financing flows and transfer payments were excluded. Thus, allowance for funds during construc-

tion, depreciation, interest, taxes, and other indirect flows were excluded. This second type of present value figure gives an estimate of the costs to society of the options. The calculation of this value based on the August analysis results in a 1990 present value of \$9.8 billion for full control and \$10.4 billion for the 340 ng/J (0.80 lb/million Btu) option. Both types of present value costs were estimated as an increment over the current standards for the years 1990 and 1995. These figures include capital costs of plants installed through that date and operation and maintenance costs for 30 years after the cutoff date. Comments are solicited regarding the calculation and use of present values for this decision. Comments are also solicited on the appropriateness of using present value costs to the utility or present value resources costs to society.

A summary of the 1995 impacts of the proposed standards is shown in table 8 based on the August analysis. The total coal capacity figure shows that by 1995 all the options have equal capacity. Thus, the options reflect differences in amount of low-sulfur coal

use, control, equipment, and variation in capacity utilization. In general, full control results in slightly lower emissions, less Western coal shipped East, higher capital expenditures, and slightly higher average residential bills than would result under the partial control options.

*Other studies.* In addition to the studies described above, EPA is aware of three other major studies of the impacts resulting from several recommended standards for powerplants. One of these studies was performed as a joint effort of the Departments of the Interior and Energy for studying coal leasing policies. Another analysis was done by the Department of Energy, and the third study was sponsored by a segment of the electric utility industry. These studies were performed for the purpose of analyzing the impacts of their respective recommended standards along with the EPA options discussed above. The results of these studies have been considered by EPA in developing the proposed standards. More detail on the results of these studies is given in the supplement to the background document (EPA 450/2-78-007a-1).

Table 1. COMPARISON OF ASSUMPTIONS  
April 1978 and August 1978

| Assumption                   | April                                                                                                                                                                                                                                                                                                                                                                                                                                                         | August                                      |
|------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------|
| Growth rates                 | 1975-1985: 5.8%/yr<br>1985-1995: 5.5%                                                                                                                                                                                                                                                                                                                                                                                                                         | 1975-1985: 4.8%/yr<br>1985-1995: 4.0%       |
| Nuclear capacity             | 1985: 108 GW<br>1990: 177<br>1995: 302                                                                                                                                                                                                                                                                                                                                                                                                                        | 1985: 97 GW<br>1990: 167<br>1995: 230       |
| Oil prices (\$ 1975)         | 1985: \$13/bbl<br>1990: \$13<br>1995: \$13                                                                                                                                                                                                                                                                                                                                                                                                                    | 1985: \$15/bbl<br>1990: \$20<br>1995: \$28  |
| General inflation rate       | 5.5%/yr                                                                                                                                                                                                                                                                                                                                                                                                                                                       | 5.5%/yr                                     |
| Annual emissions @ 0.5 floor | 0.5 lb SO <sub>2</sub> /million Btu                                                                                                                                                                                                                                                                                                                                                                                                                           | 0.32 lb SO <sub>2</sub> /million Btu        |
| Coal transportation          | Increases at general inflation rate                                                                                                                                                                                                                                                                                                                                                                                                                           | Increases at general inflation rate plus 1% |
| Coal mining labor costs      | Increases at general inflation rate                                                                                                                                                                                                                                                                                                                                                                                                                           | Increases at general inflation rate plus 1% |
| Miscellaneous                | A number of miscellaneous changes were made between the April 1978 study and the August 1978 study. These changes were either corrections or refinements of values used in the April study. Examples of these changes included revisions to the level of SIP control assumed in the model, revisions to the scrubbing costs, changes in the assumptions regarding industrial coal consumption, and changes to the coal supply curves used in the April study. |                                             |

Table 2. SUMMARY OF NATIONAL 1990 SO<sub>2</sub> EMISSIONS FROM UTILITY BOILERS<sup>a</sup>  
(million tons)

| Plant Category               | Level of Control |                      |      |                 |      |                             |      |                             |      |                             |      |
|------------------------------|------------------|----------------------|------|-----------------|------|-----------------------------|------|-----------------------------|------|-----------------------------|------|
|                              | 1975<br>Actual   | Current<br>Standards |      | Full<br>Control |      | Partial Control<br>210 ng/J |      | Partial Control<br>290 ng/J |      | Partial Control<br>340 ng/J |      |
|                              |                  | APR                  | AUG  | APR             | AUG  | APR                         | AUG  | APR                         | AUG  | APR                         | AUG  |
|                              |                  |                      |      |                 |      |                             |      |                             |      |                             |      |
| SIP/NSPS Plants <sup>b</sup> | —                | 16.8                 | 16.0 | 17.2            | 16.2 | 16.9                        | 16.2 | —                           | 16.1 | 16.7                        | 16.1 |
| New Plants <sup>c</sup>      | —                | 4.2                  | 4.4  | 1.5             | 1.2  | 2.1                         | 1.3  | —                           | 1.5  | 3.3                         | 1.8  |
| Oil/Gas Plants               | —                | 2.3                  | 1.1  | 2.5             | 1.4  | 2.3                         | 1.2  | —                           | 1.2  | 2.3                         | 1.2  |
| Total National Emissions     | 18.6             | 23.3                 | 21.4 | 21.1            | 18.9 | 21.3                        | 18.8 | —                           | 18.9 | 22.3                        | 19.1 |
| Total Coal Capacity (GW)     | 205              | 465                  | 451  | 444             | 428  | 460                         | 439  | —                           | 440  | 460                         | 444  |

SOURCE: Background Information for Proposed SO<sub>2</sub> Emission Standards - Supplement, EPA 450/2-78-007a-1, Chapters 2 and 3, August 1978.

<sup>a</sup>Results of EPA analyses completed in April 1978 and August 1978.

<sup>b</sup>Plants subject to existing state regulations or the current NSPS of 1.2 lb SO<sub>2</sub>/million Btu.

<sup>c</sup>Plants subject to the revised standards.

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Table 3. SUMMARY OF 1990 REGIONAL SO<sub>2</sub> EMISSIONS FOR UTILITY BOILERS<sup>a</sup>  
(million tons)

|                                 | 1975<br>Actual | Level of Control     |      |                 |      |                           |          |          |      |      |      |
|---------------------------------|----------------|----------------------|------|-----------------|------|---------------------------|----------|----------|------|------|------|
|                                 |                | Current<br>Standards |      | Full<br>Control |      | -----Partial Control----- |          |          |      |      |      |
|                                 |                | APR                  | AUG  | APR             | AUG  | 210 ng/J                  | 290 ng/J | 340 ng/J |      | APR  | AUG  |
| Total National Emissions        | 18.6           | 23.3                 | 21.4 | 21.1            | 18.9 | 21.3                      | 18.8     | —        | 18.9 | 22.3 | 19.1 |
| <u>Regional Emissions</u>       |                |                      |      |                 |      |                           |          |          |      |      |      |
| East <sup>b</sup>               | 9.1            | 10.8                 | 10.2 | 9.7             | 9.0  | 9.6                       | 9.0      | —        | 8.9  | 10.2 | 9.0  |
| Midwest <sup>c</sup>            | 8.8            | 8.7                  | 7.8  | 8.5             | 7.6  | 8.4                       | 7.6      | —        | 7.6  | 8.6  | 7.6  |
| West South Central <sup>d</sup> | 0.2            | 2.6                  | 2.3  | 1.8             | 1.5  | 2.0                       | 1.4      | —        | 1.5  | 2.3  | 1.6  |
| West <sup>e</sup>               | 0.5            | 1.3                  | 1.3  | 1.1             | 0.8  | 1.2                       | 0.9      | —        | 0.9  | 1.3  | 1.0  |
| Total Coal Capacity (GW)        | 205            | 465                  | 451  | 444             | 428  | 460                       | 439      | —        | 440  | 460  | 444  |

SOURCE: Background Information for Proposed SO<sub>2</sub> Emission Standards-Supplement, EPA 450/2-78-0071-1, Chapters 2 and 3, August 1978.

<sup>a</sup>Results of EPA analyses completed in April 1978 and August 1978.

<sup>b</sup>New England, Middle Atlantic, South Atlantic, and East South Central Census Regions.

<sup>c</sup>East North Central and West North Central Census Regions.

<sup>d</sup>West South Central Census Region.

<sup>e</sup>Mountain and Pacific Census Regions.

Table 4. SUMMARY OF 1990 SO<sub>2</sub> EMISSIONS BY PLANTS SUBJECT TO THE PROPOSED STANDARDS:  
AUGUST 1978 ANALYSIS

|                                                       | Level of Control     |                 |                           |          |          |
|-------------------------------------------------------|----------------------|-----------------|---------------------------|----------|----------|
|                                                       | Current<br>Standards | Full<br>Control | -----Partial Control----- | -----    | -----    |
|                                                       |                      |                 | 210 ng/J                  | 290 ng/J | 340 ng/J |
| <u>East<sup>a</sup></u>                               |                      |                 |                           |          |          |
| Total New Plant Emissions (million tons)              | 2.1                  | 0.7             | 0.7                       | 0.7      | 0.8      |
| Coal Consumption (10 <sup>15</sup> Btu)               | 3.47                 | 3.41            | 3.43                      | 3.48     | 3.47     |
| Emission Factor (#S/10 <sup>6</sup> Btu) <sup>b</sup> | 0.60                 | 0.21            | 0.21                      | 0.22     | 0.23     |
| <u>Midwest<sup>c</sup></u>                            |                      |                 |                           |          |          |
| Total New Plant Emissions (million tons)              | 0.60                 | 0.2             | 0.2                       | 0.2      | 0.2      |
| Coal Consumption (10 <sup>15</sup> Btu)               | 1.17                 | 0.79            | 0.80                      | 0.81     | 0.81     |
| Emission Factor (#S/10 <sup>6</sup> Btu) <sup>b</sup> | 0.48                 | 0.21            | 0.21                      | 0.23     | 0.26     |
| <u>West South Central<sup>d</sup></u>                 |                      |                 |                           |          |          |
| Total New Plant Emissions (million tons)              | 1.2                  | 0.2             | 0.3                       | 0.4      | 0.5      |
| Coal Consumption (10 <sup>15</sup> Btu)               | 1.93                 | 1.67            | 1.97                      | 1.96     | 1.95     |
| Emission Factor (#S/10 <sup>6</sup> Btu) <sup>b</sup> | 0.60                 | 0.14            | 0.14                      | 0.18     | 0.24     |
| <u>West<sup>e</sup></u>                               |                      |                 |                           |          |          |
| Total New Plant Emissions (million tons)              | 0.6                  | 0.1             | 0.2                       | 0.2      | 0.3      |
| Coal Consumption (10 <sup>15</sup> Btu)               | 1.25                 | 1.19            | 1.18                      | 1.19     | 1.24     |
| Emission Factor (#S/10 <sup>6</sup> Btu) <sup>b</sup> | 0.40                 | 0.09            | 0.14                      | 0.19     | 0.24     |

SOURCE: Background Information for Proposed SO<sub>2</sub> Emission Standards - Supplement, EPA 450/2-78-007a-1, Chapter 3, August 1978.

<sup>a</sup>New England, Middle Atlantic, South Atlantic, and East South Central Census Regions.

<sup>b</sup>Ratios may not be obtained exactly from figures shown here due to rounding.

<sup>c</sup>East North Central and West North Central Census Regions.

<sup>d</sup>West South Central Census Region.

<sup>e</sup>Mountain and Pacific Census Regions.

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Table 5. SUMMARY OF 1995 SO<sub>2</sub> EMISSIONS BY PLANTS SUBJECT TO THE PROPOSED STANDARDS: AUGUST 1978 ANALYSIS

|                                                       | Level of Control  |              |                           |          |          |
|-------------------------------------------------------|-------------------|--------------|---------------------------|----------|----------|
|                                                       | Current Standards | Full Control | -----Partial Control----- |          |          |
|                                                       |                   |              | 210 ng/J                  | 290 ng/J | 340 ng/J |
| East <sup>a</sup>                                     |                   |              |                           |          |          |
| Total New Plant Emissions (million tons)              | 4.0               | 1.3          | 1.3                       | 1.4      | 1.5      |
| Coal Consumption (10 <sup>15</sup> Btu) <sup>b</sup>  | 6.73              | 6.39         | 6.47                      | 6.49     | 6.67     |
| Emission Factor (#S/10 <sup>6</sup> Btu) <sup>b</sup> | 0.60              | 0.21         | 0.21                      | 0.21     | 0.22     |
| Midwest <sup>c</sup>                                  |                   |              |                           |          |          |
| Total New Plant Emissions (million tons)              | 1.2               | 0.4          | 0.4                       | 0.5      | 0.5      |
| Coal Consumption (10 <sup>15</sup> Btu) <sup>b</sup>  | 2.21              | 1.94         | 1.92                      | 1.99     | 2.00     |
| Emission Factor (#S/10 <sup>6</sup> Btu) <sup>b</sup> | 0.53              | 0.21         | 0.21                      | 0.23     | 0.26     |
| West South Central <sup>d</sup>                       |                   |              |                           |          |          |
| Total New Plant Emissions (million tons)              | 1.6               | 0.4          | 0.4                       | 0.5      | 0.7      |
| Coal Consumption (10 <sup>15</sup> Btu) <sup>b</sup>  | 2.63              | 2.77         | 2.73                      | 2.70     | 2.68     |
| Emission Factor (#S/10 <sup>6</sup> Btu) <sup>b</sup> | 0.60              | 0.15         | 0.15                      | 0.19     | 0.25     |
| West <sup>e</sup>                                     |                   |              |                           |          |          |
| Total New Plant Emissions (million tons)              | 1.1               | 0.2          | 0.3                       | 0.4      | 0.5      |
| Coal Consumption (10 <sup>15</sup> Btu) <sup>b</sup>  | 2.28              | 2.32         | 2.29                      | 2.27     | 2.27     |
| Emission Factor (#S/10 <sup>6</sup> Btu) <sup>b</sup> | 0.44              | 0.09         | 0.13                      | 0.19     | 0.22     |

SOURCE: Background Information for Proposed SO<sub>2</sub> Emission Standards - Supplement, EPA 450/2-78-007a-1, Chapter 3, August 1978

<sup>a</sup>New England, Middle Atlantic, South Atlantic, and East South Central Census Regions.

<sup>c</sup>East North Central and West North Central Census Regions.

<sup>b</sup>Ratios may not be obtained exactly from figures shown here due to rounding.

<sup>d</sup>West South Central Census Region.

<sup>e</sup>Mountain and Pacific Census Regions.

TABLE 6. SUMMARY OF IMPACTS ON FUELS IN 1990<sup>a</sup>

|                                                       | Level of Control |                   |      |              |      |                             |          |          |      |           |
|-------------------------------------------------------|------------------|-------------------|------|--------------|------|-----------------------------|----------|----------|------|-----------|
|                                                       | 1975 Actual      | Current Standards |      | Full Control |      | ----- Partial Control ----- |          |          |      |           |
|                                                       |                  |                   |      |              |      | 210 ng/J                    | 290 ng/J | 340 ng/J |      |           |
|                                                       |                  | APR               | AUG  | APR          | AUG  | APR                         | AUG      | APR      | AUG  |           |
| U.S. Coal Production (million tons)                   |                  |                   |      |              |      |                             |          |          |      |           |
| East                                                  | 396              | 441               | 465  | 467          | 449  | 464                         | 450      | -        | 450  | 418 449   |
| Midwest                                               | 151              | 298               | 275  | 375          | 318  | 353                         | 316      | -        | 294  | 307 290   |
| West                                                  | 100              | 1027              | 785  | 870          | 736  | 938                         | 752      | -        | 779  | 1055 784  |
| TOTAL                                                 | 647              | 1767              | 1525 | 1711         | 1502 | 1755                        | 1517     | -        | 1523 | 1780 1523 |
| Western coal shipped east (million tons)              | 21               | 455               | 149  | 299          | 118  | 346                         | 117      | -        | 147  | 429 152   |
| Oil/gas consumption in power plants (million bbl/day) | 3.1              | 3.0               | 1.2  | 3.3          | 1.5  | 3.1                         | 1.4      | -        | 1.4  | 3.1 1.4   |

SOURCE: Background Information for Proposed SO<sub>2</sub> Emission Standards - Supplement, EPA 450/2-78-007a-1, Chapter 2 & 3, August 1978

<sup>a</sup>Results of EPA analyses completed in April 1978 and August 1978.

## PROPOSED RULES

Table 7. SUMMARY OF 1990 ECONOMIC IMPACTS<sup>a</sup>

|                                                                              | Level of Control  |       |              |       |                                |       |          |       |          |       |
|------------------------------------------------------------------------------|-------------------|-------|--------------|-------|--------------------------------|-------|----------|-------|----------|-------|
|                                                                              | Current Standards |       | Full Control |       | ----- Partial Control 210 ng/J |       | 290 ng/J |       | 340 ng/J |       |
|                                                                              | APR               | AUG   | APR          | AUG   | APR                            | AUG   | APR      | AUG   | APR      | AUG   |
| Average monthly residential bills (\$/month)                                 | 45.31             | 43.89 | 46.39        | 44.22 | 46.20                          | 44.48 | -        | 44.38 | 45.47    | 44.38 |
| Incremental Utility capital expenditures, cumulative 1976-1990 (\$ billions) | -                 | -     | 10           | 0     | 15                             | 8     | -        | 4     | 3        | 5     |
| Incremental Annualized cost (\$ billions)                                    | -                 | -     | 2.0          | 1.9   | 1.3                            | 1.7   | -        | 1.3   | 0.3      | 1.1   |
| Incremental Cost of SO <sub>2</sub> Reduction (\$/ton)                       | -                 | -     | 895          | 754   | 640                            | 642   | -        | 511   | 303      | 485   |

SOURCE: Background Information for Proposed SO<sub>2</sub> Emission Standards - Supplement, EPA 450/2-78-007a-1, Chapters 2 & 3, August 1978.

<sup>a</sup>Results of EPA analyses completed in April 1978 and August 1978.

Table 8. SUMMARY OF 1995 IMPACTS: AUGUST 1978 ANALYSIS

|                                                               | Level of Control |                   |              |                                |          |          |
|---------------------------------------------------------------|------------------|-------------------|--------------|--------------------------------|----------|----------|
|                                                               | 1975 Actual      | Current Standards | Full Control | ----- Partial Control 210 ng/J | 290 ng/J | 340 ng/J |
| National Emissions (million tons)                             | 18.6             | 23.3              | 18.5         | 18.5                           | 18.7     | 19.0     |
| New Plant Emissions <sup>a</sup> (million tons)               | -                | 7.9               | 2.4          | 2.5                            | 2.8      | 3.2      |
| U.S. Coal Production (million tons)                           | 647              | 1865              | 1865         | 1858                           | 1868     | 1866     |
| Western Coal Shipped East (million tons)                      | 21               | 210               | 130          | 133                            | 190      | 196      |
| Oil/Gas Consumption (million bbl/day)                         | 3.1              | 0.8               | 0.9          | 0.9                            | 0.9      | 0.9      |
| Incremental Cumulative Capital Expenditures (1975 \$ billion) | -                | -                 | 32           | 26                             | 20       | 19       |
| Incremental Annualized Cost (1975 \$ billion)                 | -                | -                 | 2.6          | 2.3                            | 2.0      | 1.9      |
| Average Monthly Residential Bill (1975 \$/month)              | -                | 45.34             | 46.22        | 46.13                          | 46.12    | 46.10    |
| Total Coal Capacity (GW)                                      | 198              | 587               | 580          | 580                            | 580      | 580      |

SOURCE: Background Information for Proposed SO<sub>2</sub> Emission Standards-Supplement, EPA 450/2-78-007a-1, Chapter 3, August 1978.

<sup>a</sup>Plants subject to the revised standards.

## PARTICULATE MATTER STANDARDS

The proposed standards would limit the emissions of particulate matter to 13 ng/J (0.03 lb/million Btu) heat input and would require a 99-percent reduction in uncontrolled emissions from solid fuels and a 70-percent reduction for liquid fuels. No particulate matter control would be necessary for units firing gaseous fuels alone, and thus a percent reduction would not be required for gaseous fuels. The 20-percent opacity (8-minute average) standard that is currently applicable to steam electric generating units (40 CFR Part 60, Subpart D) would be retained under the proposed standards. An opacity standard is proposed to insure proper operation and maintenance of the particulate matter control system. If an affected facility were to comply with all applicable standards except opacity, the owner or operator may request the Administrator under 40 CFR 60.11(e) to establish a source specific opacity standard for that affected facility.

The proposed standards are based on the performance of a well designed and operated baghouse or electrostatic precipitator (ESP). EPA has determined that these control systems are the best adequately demonstrated systems 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).

EPA has evaluated data from more than 50 emission test runs conducted at eight baghouse-equipped, coal-fired steam generating units. The data from two tests exceeded the proposed standard, however, it is EPA's judgment that the emission levels at the two units which had measured emission levels above the proposed standards could be reduced to below the proposed standards through an improved maintenance program. EPA believes that baghouses with an air-to-cloth ratio of 0.6 actual cubic meters per minute per square meter (2 ACFM/ft<sup>2</sup>) would achieve the proposed standards at pressure drops of less than 1.25 kilopascals (5 in. H<sub>2</sub>O). EPA has concluded that this air/cloth ratio and pressure drop are reasonable when considering cost, energy, and nonair quality impacts.

EPA collected emission data from 21 ESP-equipped, coal-fired steam generating units. The nominal sulfur content of the coals being fired ranged from 0.4 percent to 1.9 percent. None of the 21 units tested were designed to achieve an emission level equal to or below the proposed standard of 13 ng/J (0.03 lb/million Btu) heat input; however, emissions from 9 of the 21 units were below the proposed standard. All of the units tested which were

firing coal with a sulfur content greater than 1 percent and had a hot side ESP with a specific collection area greater than 89 square meters per actual cubic meter per second (452 ft<sup>2</sup>/1,000 ACFM), or a cold side ESP with a specific collection area greater than 85 square meters per actual cubic meter per second (435 ft<sup>2</sup>/1,000 ACFM), had emission levels below the proposed standards. 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. 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 resistivity of the fly ash is higher with low-sulfur coal. To meet the proposed standard, EPA believes that an ESP used on low-sulfur coal would have to have a specific collection area from around 130 (hot side) to 200 (cold side) square meters per actual cubic meter per second (650 to 1,000 ft<sup>2</sup> per 1,000 ACFM) while an ESP used on high-sulfur coal (3.5 percent sulfur) would only require around 72 square meters per actual cubic meter per second (360 ft<sup>2</sup> per 1,000 ACFM).

ESP's have been traditionally used to control particulate emissions from powerplants. High-sulfur coal produces fly ash with a low electrical resistivity which can be readily collected with an ESP. However, low-sulfur coal produces fly ash with high electrical resistivity, which is more difficult to collect. The problem of high electrical resistivity fly ash can be reduced by using a hot side ESP (ESP located before combustion air preheater) when firing low-sulfur coal. Higher fly ash collection temperatures improve ESP performance by reducing fly ash resistivity for most types of low-sulfur coal (for example, increasing the fly ash collection temperature from 177° C (350° F) to 204° C (400° F) can reduce electrical resistivity of fly ash from low-sulfur coal by approximately 50 percent).

While EPA believes that ESP's can be applied to high-sulfur coal at reasonable costs to meet the proposed standards, it recognizes that applying a large, high efficiency ESP to a facility using low-sulfur coal to meet the proposed standards will be more expensive. In view of this, EPA believes that a baghouse control system could be applied on utility-size facilities firing low-sulfur coal at a lower cost than an ESP. Although the largest baghouse-controlled coal-fired steam generator for which EPA has particulate matter emission data is 44 MW, several larger installations are currently under construction, and EPA plans

to test a 350-MW powerplant controlled with a baghouse which recently began operation. Since baghouses are designed and constructed in modules rather than as one larger unit, there should be no technological barriers to scaling them up to a utility sized facility. Twenty-four baghouse-equipped coal-fired utility steam generators are scheduled to be operating by the end of 1978 and an additional 30 units are planned to start operation after 1978. About two-thirds of these planned units will be larger than 150-MW electrical output capacity, and more than one-third of these planned baghouse systems will be for units being fired with coal containing more than 3 percent sulfur. EPA therefore believes that baghouses have been adequately demonstrated for even the largest utility-sized facility.

EPA collected emission test data from seven coal-fired steam generators controlled by wet particulate matter scrubbers. Data from five of the seven resulted in emission levels less than 21 ng/J heat input (0.05 lb/million Btu). Data from only one of the seven were less than 13 ng/J (0.02 lb/million Btu) heat input. In view of this, EPA believes that wet particulate matter scrubbers would not be capable of complying with the proposed standards under most conditions.

EPA considered proposing the standard at a level of 21 ng/J (0.05 lb/million Btu) in order to allow the application of wet particulate matter scrubbers in addition to baghouses and ESP's. This option was rejected, because EPA believes that allowing scrubbers would cause an increase in the emissions of fine particulate matter without compensating advantages. In addition to 60 percent higher emissions, a particulate matter scrubber would require three times as much energy to operate as a dry control system, and would also increase water consumption and waste water treatment requirements. An increase in fine particulate emissions would have an adverse effect on visibility. The primary suggested advantage to allowing the use of scrubbers for particulate matter control would be to allow a single scrubber to control both SO<sub>2</sub> and particulate matter emissions which would result in a cost savings.

The Department of Energy (DOE) and others believe that the proposed standard of 3 ng/J (0.03 lb/million Btu) will preclude the use of ESP's on facilities using low-sulfur coal and require baghouse control which they believe has not been demonstrated on utility-size facilities. Because of this, DOE recommends that the standard be no less than 21 ng/J (0.05 lb/million Btu). The Utility Air Regulatory Group (UARG) also maintains that baghouses have not been adequately

demonstrated, particularly when firing high-sulfur coal. They further believe that ESP's cannot achieve the proposed standard of 13 ng/J at reasonable cost. In view of this, UARG recommends an emission limitation of 34 ng/J (0.08 lb/million Btu). In doing so, they maintain a 34-ng/J standard would encourage baghouses but not eliminate precipitators from use.

EPA has investigated the possibility that FGD control systems affect particulate matter emissions. Three possible mechanisms were investigated: (1) FGD system sulfate carryover from the scrubber slurry, (2) particulate matter removal by the FGD system, and (3) particulate matter generation by the FGD system through condensation of sulfuric acid mist ( $H_2SO_4$ ).

To address the first mechanism, EPA obtained data from three different steam generators that were all equipped with FGD systems and that had low particulate matter emission levels at the FGD inlet. The data from all three facilities indicated that particulate emissions did not increase through the FGD system. Proper mist eliminator design and maintenance is important in preventing scrubber liquid entrainment which could cause the outlet particulate loading to exceed inlet particulate loading.

In relation to the second mechanism, FGD system removal of particulate matter, the data from the three FGD systems available to EPA indicated that particulate matter emissions were reduced by the FGD systems in all three cases. That is, the particulate matter discharge concentration from the FGD system was less than the concentration at the FGD inlet. This property has been particularly noted at steam generators equipped with ESP's upstream of FGD systems.

The third mechanism is the potential condensation of sulfuric acid mist ( $H_2SO_4$ ) from sulfur trioxide ( $SO_3$ ) in the flue gas. At a typical steam generator, 97 to 99 percent of the fuel sulfur is converted to  $SO_3$ , and 1 to 3 percent is converted to  $SO_2$ . Typical stack gas temperatures at a coal-fired steam generator without an FGD system are between 150° C and 200° C (300° F to 400° F). At these temperatures, most  $SO_3$  remains in a gaseous state and does not form sulfuric acid. At lower temperatures, water vapor condenses and combines with  $SO_3$  to form sulfuric acid. The dewpoint temperature for sulfuric acid ranges between 120° C (250° F) and 175° C (350° F). The lower temperature would correspond to low-sulfur coal and higher temperature would correspond to high-sulfur coal.

Available test data indicate that an FGD system would remove about 50 percent of the  $SO_3$  in the flue gas and thus reduce the potential for sulfuric

acid mist formation. However, if sulfuric acid mist is formed in the flue gases, there is a potential for its interference with the particulate matter performance test. Under method 5, a sample is extracted at a probe temperature of about 160° C (320° F). This assures that  $SO_3$  does not condense on the sampling filter when sampling powerplants that do not have FGD systems. However, when sampling powerplants with FGD systems (particularly when combusting high-sulfur coal), there is a potential for sulfuric acid mist to form at the reduced flue gas temperatures. If acid mist forms, it may interact within the sampling train to form sulfate compounds that are not vaporized at the 160° C (320° F) sampling temperature. Also, sulfuric acid mist may remain deposited within the test probe itself. In either case, the net result could be a high measurement of particulate matter.

EPA obtained data from three FGD equipped powerplants to determine acid mist formation potential. All of these plants were firing low-sulfur coal. The data indicate that  $SO_3$  conversion to sulfuric acid mist is not a problem. EPA believes these data support the conclusion that an FGD system on low-sulfur coal-fired powerplants does not increase particulate emissions through sulfuric acid formation. Thus, EPA believes compliance with the proposed particulate matter standard is demonstrated to be achievable when firing low-sulfur coal.

In a case where an FGD system is used with higher sulfur coal, sufficient data have not become available to fully assess the effect of sulfuric acid formation on measured particulate matter. The proposed standard is based on emission test data at the particulate matter control device discharge prior to any FGD system. EPA plans to continue investigating this subject and will consider any data available on the impact of sulfuric acid mist on the particulate matter standard.

The 1977 amendments require that EPA specify, in addition to an emission limitation, a percent reduction in uncontrolled emission levels for fossil fuel-fired stationary sources. The proposed standard would require a 99-percent reduction for solid fuels and a 70-percent reduction for liquid fuels. Because of the difficulty of sampling particulate matter upstream of the control device (due to the complex particulate matter sampling conditions), the proposed standard would not require direct performance testing for the particulate matter emission reduction level. The percent reduction is not controlling, and performance testing for the emission limitation would satisfy the requirements for performance testing.

EPA is requesting comments on the proposed level of the particulate matter standard and the basis for the standard.

#### NO<sub>x</sub>

The proposed NO<sub>x</sub> emission standards are based on emission levels achievable with a properly designed and operated steam generator which utilizes combustion modification techniques to reduce NO<sub>x</sub> formation. The proposed standards are as follows:

(1) 86 ng/J heat input (0.20 lb/million Btu) from the combustion of any gaseous fuel, except gaseous fuel derived from coal;

(2) 130 ng/J heat input (0.30 lb/million Btu) from the combustion of any liquid fuel, except shale oil and liquid fuel derived from coal;

(3) 210 ng/J heat input (0.50 lb/million Btu) from the combustion of sub-bituminous coal, shale oil, or any solid, liquid, or gaseous fuel derived from coal;

(4) 340 ng/J (0.80 lb/million Btu) 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 would be exempt from the NO<sub>x</sub> standards and monitoring requirements;

(6) 260 ng/J (0.60 lb/million Btu) from the combustion of any solid fuel not specified under (3), (4), or (5);

(7) Percent reductions in uncontrolled NO<sub>x</sub> emission levels would be required; however, the percent reduction would not be controlling, and compliance with the NO<sub>x</sub> emission limits (ng/J) would assure compliance with the percent reduction requirements. the National Appeals Board

Most new electric utility steam generating units are expected to burn pulverized coal. Consequently, the NO<sub>x</sub> studies used to develop the proposed standards have concentrated on the combustion of pulverized coal. The proposed standards for pulverized coal are based on the application of combustion modification techniques (i.e., staged combustion, low excess air, and reduced heat release rate) which EPA has concluded represent the best demonstrated 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 electric utility power plants.

The proposed standards would require continuous compliance (based on a 24-hour average), except during periods of startup, shutdown, or malfunction as provided under 40 CFR 60.8. Percent reduction requirements are in-

cluded in the proposed standards as a result of provisions in the 1977 Amendments. As with the proposed particulate matter standard, the percent reductions for NO<sub>x</sub> are not controlling, and compliance testing for the NO<sub>x</sub> emission limitations (ng/J) would satisfy all compliance testing requirements for NO<sub>x</sub>.

Combustion modification techniques limit the formation of NO<sub>x</sub> in the boiler by reducing flame temperatures and by minimizing the availability of oxygen during combustion. Elevated temperatures and high oxygen levels would otherwise enhance the formation of NO<sub>x</sub>. The levels to which NO<sub>x</sub> emissions can be reduced with combustion modifications depend on the type of fuel burned, the boiler design, and boiler operating practices. All four of the major boiler manufacturers utilize combustion modification techniques in their modern units; however, some manufacturers' techniques may be more effective than others.

EPA has conducted NO<sub>x</sub> emission tests at six modern electric utility steam generating units which burn pulverized coal, representing two of the major boiler manufacturers. These tests indicate that during low NO<sub>x</sub> operation of modern units, emission levels below 210 ng/J heat input (0.50 lb/million Btu) are easily attainable. If the potential side effects associated with low NO<sub>x</sub> operation were not considered, it would be reasonable to establish an NO<sub>x</sub> emission limit for pulverized coal-fired units at 210 ng/J heat input.

The side effects EPA has considered include: Boiler tube wastage (corrosion); slagging; increased emissions of particulates, carbon monoxide, polycyclic organic matter, and other hydrocarbons; boiler efficiency losses; carbon loss in the ash; low steam temperatures; and possible operating hazards (including boiler explosions). In EPA's judgment only boiler tube wastage could be a potential problem at NO<sub>x</sub> emission levels necessary to meet a standard of 210 ng/J.

Tube wastage is the deterioration of boiler tube surfaces due to the corrosive effects of ash in the presence of a reducing atmosphere. A reducing atmosphere often results from operation of a boiler under conditions required to minimize NO<sub>x</sub> emissions. The severity of tube wastage is believed to vary with several factors, but especially with the quality of the coal burned. For example, high sulfur Eastern coal generally causes more of a tube wastage problem than low sulfur Western coal. Serious tube wastage can shorten the life of a boiler and result in expensive repairs.

Because of the potential problem from tube wastage, EPA does not believe that an emission limit below the

proposed level of 260 ng/J heat input for Eastern bituminous coals would be reasonable even though emission data alone would tend to support a lower limit. For low rank Western coals, however, there is a much smaller tube wastage potential at low NO<sub>x</sub> levels, and a lower emission limit is justified. Hence, EPA is proposing an emission limit of 210 ng/J heat input for units burning low rank Western coals. These coals are classified in the proposed standards as subbituminous, according to ASTM methods. EPA believes that the proposed distinction made between low rank Western (subbituminous) coal and other coals represents the best method for distinguishing between coals with low and high tube wastage potentials.

Although most new utility power plants will fire pulverized coal, other fuels may also be burned. Emission limits for these fuels are also proposed.

The proposed NO<sub>x</sub> emission limits for units which burn liquid and gaseous fuels are at the same levels as the emission limits originally promulgated in 1971 under subpart D for large steam generators which burn oil and gas. EPA did not conduct a detailed study of combustion modification or NO<sub>x</sub> flue gas treatment for oil- or gas-fired boilers because few, if any, oil- or gas-fired electric utility power plants are expected to be built in the future.

Several studies have been conducted which indicate that emissions from the combustion of liquid and gaseous fuels which are derived from coal, such as solvent refined coal and low Btu synthetic gas, may exceed the proposed emission limits for liquid fuels (130 ng/J) and gaseous fuels (86 ng/J). The reason is because fuels derived from coal will have fuel bound nitrogen contents which approach the levels found in coal rather than in natural gas and oil. Based on limited emission data from pilot-scale facilities and on the known emission characteristics of coal, EPA believes that an achievable emission limit for solid, liquid, or gaseous fuels derived from coal would be 210 ng/J (0.50 lb/million Btu). Tube wastage of 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.

Very little is known about the emission characteristics of shale oil. However, since shale oil typically has a higher fuel-bound nitrogen content than fuel oil, it may be impossible for a well-controlled unit burning shale oil to achieve the proposed NO<sub>x</sub> 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<sub>x</sub> emissions from shale oil combustion. Consequently, EPA proposes to limit NO<sub>x</sub> emissions from units burning shale oil to 210 ng/J, the same limit proposed for subbituminous coal. 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 subpart D standards because the only furnace design believed capable of burning coal refuse, the slag tap furnace, inherently produces NO<sub>x</sub> emissions in excess of the NO<sub>x</sub> standard. Since no new information has become available, EPA would continue the coal refuse exemption under the proposed standards.

The proposed emission limits for lignite combustion were developed earlier as amendments to the original standards under subpart D. Since no new information on NO<sub>x</sub> emission rates resulting from lignite combustion in electric utility power plants has become available, the lignite limits have been incorporated into these proposed standards without revision.

While EPA believes that the proposed emission limitations for bituminous and subbituminous coals can be achieved without adverse effects, UARG recommends that the present NO<sub>x</sub> emission limitation of 300 ng/J (0.7 lb/million Btu) be retained. In so doing, they argue that the potential adverse side effects that may result from operating a boiler under conditions required to meet the proposed standards have not been adequately studied over the long term. They also expressed concern that the proposed standards could have an anticompetitive effect, since they believe there may be only one boiler vendor who could meet the proposed standards on a continuous basis. Finally, they question whether there is sufficient continuous monitoring experience to warrant basing compliance on continuous monitoring results.

#### STUDIES

The background information including environmental and economic assessments for the proposed standards is divided into 4 documents, each with a title and a document number as follows:

"Electric Utility Steam Generating Units: Background Information for Proposed NO<sub>x</sub> Emission Standards," EPA 450/2-78-006a;

"Electric Utility Steam Generating Units: Background Information for Proposed Particulate Matter Emission Standards," EPA 450/2-78-006a;

"Electric Utility Steam Generating Units: Background Information for Proposed SO<sub>2</sub> Emission Standards," EPA 450/2-78-007a; and

"Electric Utility Steam Generating Units: Background Information for Proposed SO<sub>2</sub>

Emission Standards—Supplement," EPA 450/2-78-007a-1.

Much of the supporting information within the background information documents was obtained from consultant studies sponsored by EPA. Reports covering these studies are included in the docket at EPA headquarters and are available for inspection during normal office hours at each EPA regional office. The titles of the consultant studies are as follows:

1. "Flue Gas Desulfurization Systems: Design and Operating Parameters, SO<sub>2</sub> Removal Capabilities, Coal Properties and Reheat."
2. "Flue Gas Desulfurization System Capabilities for Coal-Fired Steam Generators."
3. "Boiler Design and Operating Variables Affecting Uncontrolled Sulfur Emissions from Pulverized Coal-Fired Steam Generators."
4. "Effects of Alternative New Source Performance Standards on Flue Gas Desulfurization System Supply and Demand."
5. "Evaluation of Physical Coal Cleaning as an SO<sub>2</sub> Emission Control Technique."
6. "The Impact of Modification/Reconstruction of Steam Generators on SO<sub>2</sub> Emissions."
7. "The Energy Requirements for Controlling SO<sub>2</sub> Emissions from Coal-Fired Steam/Electric Generators."
8. "The Solid Waste Impact of Controlling SO<sub>2</sub> Emissions from Coal-Fired Steam-Electric Generators."
9. "Water Pollution Impact of Controlling SO<sub>2</sub> Emissions from Coal-Fired Steam/Electric Generators."
10. "Particulate and Sulfur Dioxide Emission Control Costs for Large Coal-Fired Boilers."
11. "Review of New Source Performance Standards for SO<sub>2</sub> Emissions from Coal-Fired Utility Boilers."
12. "The Effect of Flue Gas Desulfurization Availability on Electric Utilities."
13. "Effects of Alternative New Source Performance Standards for Coal-Fired Electric Utility Boilers on the Coal Markets and Utility Capacity Expansion Plans."
14. "Flue Gas Desulfurization System Manufacturers Survey."
15. "Assessment of Manufacturer Capacity to Meet Requirements for Particulate Control in Utility and Industrial Boilers."
16. "Flue Gas Desulfurization Cost for Large Coal-Fired Boilers, August 10, 1978."
17. "The Ability of Electric Utilities with FGD to Meet Energy Demands."

In addition to the consultant studies, EPA studies were performed. One study involved the installation and operation of continuous SO<sub>2</sub> monitors on the inlet and outlet of commercial-scale FGD units. The purposes of the study were to determine: (1) The statistical characteristics of coal-fired boiler and FGD operation, (2) the variability of SO<sub>2</sub> inlet concentrations, (3) the ability of FGD to "damp out" SO<sub>2</sub> variability, and (4) SO<sub>2</sub> emissions as a function of averaging period.

A second EPA study included a diffusion modeling analysis to estimate the maximum ground-level concentration of SO<sub>2</sub> that would occur around

small, medium, and large power plants for emission rates with and without flue gas reheat. The study also examined the estimated SO<sub>2</sub> concentrations that would occur around multi-boiler facilities. Surface and upper-air meteorological data for eight different geographical areas were used in the study.

EPA has also supplemented the economic, energy, and environmental impact assessment set forth in the background information document for the SO<sub>2</sub> standard (EPA 450/2-78-007a) by conducting two additional analyses. The first was initiated in February 1978, and results became available in late April. The second, which was completed in August, used revised assumptions pertaining to utility growth rates, oil prices, etc. The results of these studies are presented in sections 2 and 3 of the "Electric Utility Steam Generating Units: Background Information for Proposed SO<sub>2</sub> Emission Standards—Supplement," EPA 450/2-78-007a-1.

EPA has also taken into consideration studies prepared by other Governmental Agencies. One study is "The Demand for Western Coal and its Sensitivity to Key Uncertainties," draft report, 2nd edition, June 1978, which assessed the potential impact of this proposal on coal demand. This report was prepared by a consultant for the Department of Interior and the Department of Energy. In addition the analysis of alternative standards prepared by the Department of Energy, and transmitted to EPA by Mr. John F. O'Leary, Deputy Secretary, on July 6 and August 11, 1978, was also considered.

A task force of American experts in scrubber technology visited Japan to evaluate Japanese scrubber performance. The findings (Maxwell, Elder and Morasky, "Sulfur Oxides Control Technology in Japan," June 30, 1978) were also considered by EPA.

#### PERFORMANCE TESTING

##### PARTICULATE STANDARDS

Compliance with the proposed particulate matter standards would be determined by using EPA method 5 operated at a filter temperature up to 160°C (320°F). As an option, EPA method 17 may be used for stack gas temperature less than 160°C. EPA method 3 would be used to determine oxygen or carbon dioxide concentrations. These concentration measurements would then be used to compute particulate emissions in units of the standard as specified in proposed EPA method 19.

Compliance with opacity standards could be determined at any time by visual observations using EPA method 9. Except during startups, shutdowns, and malfunctions, all data from visual observations would be used for deter-

mining compliance with the proposed opacity standard.

A continuous monitoring system for opacity would be required in the stack except when firing only gaseous fuels. The opacity data from the continuous monitor would not be used to determine compliance with the opacity standard. It would be used to assist in assuring the particulate matter control system is properly operated and maintained.

#### SO<sub>2</sub> AND NO<sub>x</sub> STANDARDS

**Performance tests.** Compliance with the proposed SO<sub>2</sub> and NO<sub>x</sub> standards would be determined using the data obtained from the required continuous monitoring systems. If an FGD system were used for SO<sub>2</sub> control, continuous SO<sub>2</sub> emission monitors would be required both upstream and downstream of the FGD system and used to determine compliance with the proposed 85 percent SO<sub>2</sub> reduction. As an option, compliance with the proposed SO standards could be determined using both an "as fired" fuel sampler to determine the sulfur content and heating value of the fuel fired to the boiler, and a continuous SO<sub>2</sub> emission monitor after the FGD system to measure SO<sub>2</sub> emissions discharged into the atmosphere. In addition to crediting the SO<sub>2</sub> removed by the FGD system, this option would provide credit for sulfur removed by coal pulverizers and by the bottom ash and fly ash. The SO<sub>2</sub> percent reduction requirement and emission limitation would both be based on emission levels averaged over a 24-hour (daily) period. If fuel is treated prior to combustion to reduce SO<sub>2</sub> emissions, a sulfur removal credit would also be allowed. Procedures for determining sulfur removal credits are proposed under § 60.48a with EPA method 19.

Performance testing to determine compliance with the NO<sub>x</sub> emission limitation (ng/J) would be determined on a continuous basis through the use of a continuous NO<sub>x</sub> emission monitor. NO<sub>x</sub> emission data would be averaged over a 24-hour (daily) period. Performance testing to determine compliance with the percent reduction requirements for NO<sub>x</sub> would not be required. An affected facility would be assumed to be in compliance with the NO<sub>x</sub> reduction requirements provided the facility is in compliance with the applicable NO<sub>x</sub> emission limitation.

When the NO<sub>x</sub> or SO<sub>2</sub> continuous monitoring system fails to operate properly, the source owner or operator would obtain emission data by:

1. Operation of a second monitoring system, or
2. Conducting manual tests using EPA reference methods during the period the continuous monitoring system is inoperative.

Operation of a second monitoring system would mean that the source owner would have a second system in operation at all times. Conducting the manual tests would mean that the source owner would have trained manpower available on an immediate basis to collect samples while the continuous monitoring system is inoperative. Manual test runs would be required on an hourly basis.

Since compliance with the proposed SO<sub>2</sub> and NO<sub>x</sub> standards would be determined by continuous monitors, EPA is currently developing additional quality assurance procedures. These procedures would not change the present performance specifications for continuous monitoring systems, but would provide additional periodic field tests to assure the accuracy of the monitoring data. Appendix E under 40 CFR Part 60 is being reserved for these additional quality assurance procedures. Electric utility powerplants that would be subject to the proposed standard would be subject to the quality assurance procedures under appendix E when completed. This should not pose a problem since new sources affected by this proposed action are not expected to begin operation until about 1984.

**Fuel pretreatment.** Pretreatment of a fuel to remove sulfur or increase heat content would be credited toward the SO<sub>2</sub> percent reduction requirement. For example, by pretreatment of a 2.3 percent sulfur fuel (equivalent to 1,000 ng/J) to 1.7 percent sulfur (750 ng/J; 25 percent sulfur removal), the FGD system SO<sub>2</sub> control requirement would be reduced from 85 percent to 80 percent (750 ng/J reduced to 150 ng/J). An 85 percent emission reduction (1,000 ng/J to 150 ng/J) would be necessary for an FGD system if the fuel were fired untreated.

Fuel pretreatment credits would be given for removal of sulfur from fuel, including the resulting increase in fuel heat content. Examples of the type of equipment or processes for which credit would be given are:

1. Physical coal cleaning.
2. Solvent refining of coal.
3. Liquification of coal.
4. Gasification of coal.

Rotary breakers or coarse screens used to separate rock and other material from raw coal prior to processing or shipment are considered an integral part of the coal mining process and would not be considered as fuel pretreatment (see section 4.5.2.2 of EPA 450/2-78-007a-1).

The proposed standard would not require fuel to be pretreated before firing but would allow credit for pretreatment if used. The amount of sulfur removed by a fuel pretreatment process would be determined following procedures in EPA method 19 (appen-

dix A). The owner or operator of the electric utility who would use the credit would be responsible for insuring that the EPA method 19 procedures are followed in determining SO<sub>2</sub> removal credit for pretreatment equipment.

#### MISCELLANEOUS

As prescribed by section 111, 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. 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, and on the proposed test methods.

Under EPA's "new" 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 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 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.

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 exist-

## PROPOSED RULES

tence 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 proposed standards meet the criteria for preparation of a regulatory analysis as outlined in the Executive order. Therefore, a regulatory analysis has been prepared as required. The analysis is contained in the background information documents for the proposed standards. The regulatory analysis is not being published as a separate document because the work was begun before the President's Executive order was published. However, in order to present a better understanding of the analyses contained in the background information documents, a summary of the analyses is included in the preamble. The summary discusses in detail the alternatives considered.

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 the proposed amendments are substantial and has prepared an economic impact assessment and included the required information in the background information documents.

Dated: September 11, 1978.

DOUGLAS M. COSTLE,  
Administrator.

It is proposed that 40 CFR Part 60 be amended by revising the heading and § 60.40 of Subpart D, by adding a new Subpart Da, by adding a new reference method to Appendix A, and by reserving Appendix E as follows:

1. The heading for Subpart D is revised to read as follows:

**Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators Constructed After August 17, 1971**

2. Section 60.40 is amended by adding paragraph (a)(3) as follows:

§ 60.40 Applicability and designation of affected facility.

(a) \* \* \*

(3) Is not subject to the provisions of Subpart Da.

\* \* \* \* \*

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

3. 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) Which 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 fossil fuel in the steam generator are subject to this subpart. (The gas turbine emissions are subject to Subpart GG.)

§ 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.

(a) "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). A steam generating unit includes the following systems:

(1) Fuel combustion system (including bunker, coal pulverizer, crusher, stoker, and fuel burners, as applicable).

(2) Combustion air system.

(3) Steam generating system (firebox, boiler tubes, etc.).

(4) Draft system (excluding the stack).

(b) "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 maximum design electrical output capacity to an electrical 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 energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

(c) "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.

(d) "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.

(e) "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.

(f) "Coal refuse" means waste products from coal mining, physical coal cleaning, and coal refining operations (e.g. culm, gob, or other rejects) containing coal, ash matrix material, clay, and organic and inorganic material.

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

(1) For particulate matter is:

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

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

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

(3) For nitrogen oxides is:

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

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

(iii) 990 ng/J heat input (2.3 lb/million Btu) for solid fuels.

(h) "Combined cycle gas turbine" means a stationary gas turbine system where heat is recovered from the exhaust gases by passing the exhaust gases through a steam generating unit. fossil fuel may also be combusted in the steam generating unit.

(i) "Utility company" means the largest organization, business, or governmental entity that owns the affected facility (e.g. a holding company with operating subsidiary companies).

(j) "System capacity" means the sum of the rated electrical output capacity of all electric generating equip-

ment which is owned by the utility company and which is being operated or is capable of being operated (including fossil-fuel-fired steam generators, internal combustion engines, gas turbines, and nuclear power plants). The electrical generating capacity of electric generating equipment under multiple ownership is prorated based on ownership.

(k) "System emergency reserves" means the rated capacity of the single largest steam electric generating unit (including fossil-fuel-fired steam generators, internal combustion engines, gas turbines, and nuclear power plants) owned by the utility company. The electric generating capacity of electric generation equipment under multiple ownership is prorated based on ownership.

(l) "Available system capacity" means the capacity determined by subtracting the system load and the system emergency reserves from the system capacity.

(m) "Spinning reserve" means the sum of the unutilized capacity of all units of the utility company that are synchronized to the power distribution system and that are capable of immediately accepting additional load. The electrical generating capacity of electric generation equipment under multiple ownership is prorated based on ownership.

(n) "Emergency condition" means that period of time:

(1) When the electric generation load on an affected facility with a malfunctioning flue gas desulfurization system cannot be shifted because all available system capacity is being operated, or

(2) When all available system capacity is not being utilized and electric generation load is being shifted as quickly as possible from the affected facility to:

(i) One or more electric generating units held in spinning reserve, or  
(ii) Another electrical generation system through the purchase of electric power.

(o) "Noncontinental areas" means the State of Hawaii, the Virgin Islands, Guam, American Samoa, and the Commonwealths of Puerto Rico and the Northern Mariana Islands.

(p) "Commercial demonstration plant" means:

(1) An affected facility commercially demonstrating an emerging technology, or

(2) Any of the affected facilities that combust the coal-derived fuel produced at a commercial demonstration coal conversion plant, demonstrating an emerging technology.

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

**§ 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 heat input (0.03 lb/million Btu) 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, 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 any gases which contain sulfur dioxide in excess of:

(1) 340 ng/J heat input (0.80 lb/million Btu) derived from the combustion of any liquid or gaseous fuel;

(2) 520 ng/J heat input (1.2 lb/million Btu) derived from the combustion of any solid fuel except as provided under paragraph (b) of this section; and

(3) 15 percent of the potential combustion concentration (85 percent reduction) when combusting solid, liquid, or gaseous fuel, except as provided under paragraphs (b) and (c) of this section.

(b) The sulfur dioxide emissions allowed under paragraph (a) of this section may be exceeded up to three 24-hour periods during any calendar month, however, the sulfur dioxide emissions must be reduced to less than 25 percent of the potential combustion concentration (75 percent reduction) at all times.

(c) The requirements under paragraph (a)(3) of this section do not apply when any of the following conditions are met:

(1) The sulfur dioxide emitted to the atmosphere is less than 86 ng/J heat input (0.20 lb/million Btu).

(2) The affected facility is located in a noncontinental area.

(3) The affected facility is operated under an SO<sub>2</sub> commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.45a.

(d) For purposes of determining compliance with provisions of paragraph (a)(3) of this section, any reduction in potential sulfur dioxide emissions resulting from the following may be credited in accordance with § 60.48a(b):

(1) Fuel pretreatment.  
(2) Coal pulverizers.  
(3) Bottom ash and fly ash interaction.

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

$$PS_{pror} = x(340) + y(520)/100$$

where:

$PS_{pror}$  is the prorated standard for sulfur dioxide when combusting different fuels simultaneously (ng/J heat input).

$x$  is the percentage of total heat input derived from the combustion of gaseous and liquid fuel.

$y$  is the percentage of total heat input derived from the combustion of solid fuel.

**§ 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 any gases which contain nitrogen oxides in excess of:

(1) 86 ng/J heat input (0.20 lb/million Btu) derived from the combustion of any gaseous fuel, except gaseous fuel derived from coal;

(2) 130 ng/J heat input (0.30 lb/million Btu) derived from the combustion of any liquid fuel, except shale oil and liquid fuel derived from coal;

(3) 210 ng/J heat input (0.50 lb/million Btu) derived from the combustion of:

(i) Subbituminous coal,  
(ii) Shale oil, or  
(iii) Any solid, liquid, or gaseous fuel derived from coal; except as provided under paragraph (c) of this section.

(4) 260 ng/J heat input (0.60 lb/million Btu) derived from the combustion of any solid fuel not specified under paragraphs (a)(3), (a)(5) or (b) of this section;

(5) 340 ng/J heat input (0.80 lb/million Btu) derived 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;

(6) 75 percent of the potential combustion concentration (25 percent re-

duction) when combusting gaseous fuel;

(7) 70 percent of the potential combustion concentration (30 percent reduction) when combusting liquid fuel; and

(8) 35 percent of the potential combustion concentration (65 percent reduction) when combusting solid fuel.

(b) Combustion of a fuel containing more than 25 percent, by weight, coal refuse is exempt from both the provisions of § 60.47a(a)(3) and paragraph (a) of this section.

(c) The requirements under paragraph (a) of this section do not apply when an affected facility is operated under an NO<sub>x</sub> commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.45a.

(d) When two or more fuels, except as provided under paragraphs (a)(5) or (b) of this section, are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$$PS_{NO_x} = w(86) + x(130) + y(210) + z(260)/100$$

where:

$PS_{NO_x}$  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 (d) of this section. Commercial demonstration permits may only be issued by the Administrator, and this authority will not be delegated.

(b) An owner or operator who is issued an SO<sub>2</sub> commercial demonstration permit by the Administrator is not subject to the SO<sub>2</sub> control requirements under § 60.43a(a)(3) but must, as a minimum, reduce SO<sub>2</sub> emissions to 20 percent of the potential combustion concentration (80 percent SO<sub>2</sub> control on a 24-hr basis).

(c) An owner or operator who is issued an NO<sub>x</sub> commercial demonstration permit by the Administrator is not subject to the NO<sub>x</sub> control requirements under § 60.44a but must, as a

minimum, reduce NO<sub>x</sub> emissions to 300 ng/J heat input (0.70 lb/million Btu; 24-hour average).

(d) 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 MW electrical capacity |
|---------------------------------------------------------|-----------------|-----------------------------------|
| Solvent refined coal (I).....                           | SO <sub>2</sub> | 6,000-10,000                      |
| Fluidized bed combustion SO <sub>2</sub> (atmospheric). |                 | 400-3,000                         |
| Fluidized bed combustion SO <sub>2</sub> (pressurized). |                 | 400-1,200                         |
| Coal liquefaction.....                                  | NO <sub>x</sub> | 750-10,000                        |
| Total allowable for all technologies.                   |                 | 15,000                            |

#### § 60.46a Compliance provisions.

(a) Compliance with the particulate matter emission limitation under § 60.42(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)(1), (2), (3), (4), and (5) as applicable, constitutes compliance with the percent reduction requirements under § 60.44a(a)(6), (7), and (8).

(c) Following the initial performance tests for sulfur dioxide and nitrogen oxides required under § 60.8, each 24-hour period constitutes a separate performance test. The nitrogen oxides emission standards under § 60.44a apply at all time 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 an affected facility with a malfunctioning flue gas desulfurization system may continue operation if sulfur dioxide emissions are minimized by:

(1) Continued operation of all operable flue gas desulfurization system modules,

(2) Only by-passing flue gases around totally inoperable flue gas desulfurization system modules, and

(3) Designing, constructing, and operating a spare flue gas desulfurization system module in affected facilities larger than 365 MW heat input (1,250 million Btu/hr).

#### § 60.47a Emission monitoring.

(a) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference 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 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(c), 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.

(4) If a facility which complies with § 60.43a(a) solely through the provisions under § 60.43a(d), then sulfur dioxide emissions are only monitored at the outlet of the sulfur dioxide control device.

(c) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring 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 an oxygen or carbon dioxide monitoring system to measure the oxygen or carbon dioxide content of the flue gas at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

(e) The owner or operator of an affected facility shall operate continuous emission monitoring systems during all periods the affected facility is operated except for the following:

(1) A maximum of sixty (60) minutes each day for daily zero and calibration checks or adjustments.

(2) A maximum of eight (8) hours per month for routine maintenance.

(f) During periods of operation of the affected facility when continuous monitoring systems (and spare monitoring systems if used) are not operable, the owner or operator of the affected facility shall conduct performance tests consisting of manual testing each hour until the continuous monitoring system is returned to service. Each hourly test is performed as follows:

(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 shall be 20 minutes and the minimum sampling volume 0.02 dscm (0.71 dscf) for each sample. The arithmetic mean of two samples taken at approximately 30-minute intervals constitutes one run. The arithmetic mean of the runs obtained during a 24-hour period is reported as the average for that period. For determination of FGD removal efficiency, inlet and outlet sampling is conducted simultaneously.

(3) For method 7, each run consists of at least four grab samples taken at approximately 15-minute intervals. The arithmetic mean of the four samples constitutes the 1-hour run. The arithmetic mean of the runs obtained during a 24-hour period is reported as the average for that period.

(4) For method 3, the oxygen or carbon dioxide sample is obtained simultaneously at the same location in the duct as the samples collected using methods 6 and 7. For method 7, the oxygen sample is obtained using the grab sampling and analysis procedures of method 3.

(5) For each run using method 19 in appendix A to this part, the emissions expressed in ng/J (lb/million Btu) are determined. The arithmetic mean of the runs performed during a 24-hour period is reported as the average for that period.

(g) The following procedures are used for 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:

(Parts per million)

| Fossil fuel       | Span value for nitrogen oxides |
|-------------------|--------------------------------|
| Gas.....          | 500                            |
| Liquid.....       | 500                            |
| Solid.....        | 1,000                          |
| Combinations..... | $500(x+y) + 1,000z$            |

where:

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

$y$  = the fraction 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 (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 200 percent of the potential emissions of the fuel fired, and at the outlet of the sulfur-dioxide-control device is 50 percent of potential emissions. When the percent fuel sulfur content changes by 0.5 (24-hour average) or more, the continuous monitoring system shall be respanned.

(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 method 5 or method 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 (320° F).

(5) For determination of particulate emissions, the oxygen or carbon-dioxide sample is obtained simultaneously with each run of method 5 or method 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 method 5 or method 17, the emission rate expressed in ng/J is determined using the oxygen or carbon-dioxide results and particulate results obtained under this section, and using the dry F-factor and dry basis emission rate calculation procedure contained in method 19 (appendix A).

(b) The following procedures and methods are used to determine compliance with the sulfur dioxide standard under § 60.43a:

(1) Determine the percent of potential combustion concentration (percent PCC) emitted to the atmosphere as follows:

(i) Determine the percent sulfur reduction achieved by any fuel pretreatment using the procedures in method 19 (appendix A; optional procedure). Calculate the average percent reduction on a quarterly basis using fuel analysis data.

(ii) Determine the percent sulfur dioxide reduction achieved by any sulfur dioxide control system using continuous sulfur dioxide emission monitors or an "as fired" fuel monitor (optional procedure) in conjunction with a continuous sulfur-dioxide-emission monitor and following the procedures in method 19 (appendix A). If 24 hours of data are not available (such as during startup or shutdown), all available valid data are averaged for each 24-hour period.

(iii) Determine atmospheric sulfur dioxide emissions as a percent of the potential combustion concentration (percent PCC) as follows: Use the results obtained in paragraphs (b)(1) (i) (optional) and (ii) of this section and the procedures in method 19 (appendix A) to calculate the overall percent reduction (percent  $R_o$ ) of the potential sulfur dioxide emissions. Results are calculated for each 24-hour period using the quarterly average percent sulfur reduction determined for fuel pretreatment from the previous quarter and the sulfur dioxide reduction for each 24-hour period determined for each day in the current quarter. Calculate the percent of potential combustion concentration emitted to the atmosphere using the following equation:

$$\text{Percent PCC} = 100 - \text{percent } R_o$$

(2) Determine sulfur dioxide and nitrogen oxides emission rates using method 19 (appendix A). Emission rates are calculated for each 24-hour period and shall be considered to constitute a three-run performance test. If 24 hours of data are not available in a 24-hour period (such as during startup or shutdown), all available valid data for the period are averaged.

(c) The procedures and methods outlined in method 19 (appendix A) are

used in conjunction with the 24-hour nitrogen-oxides emission data collected under § 60.47a to determine compliance with the applicable nitrogen oxides standard under § 60.44a.

(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.

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

#### § 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 continuous monitors are submitted to the Administrator.

(b) For sulfur dioxide and nitrogen oxides, all emission data (24-hour daily average) collected subsequent to the initial performance test are submitted to the Administrator. The required data include the following information for each 24-hour period:

- (1) Calendar date;
- (2) Sulfur dioxide and nitrogen oxides emission rates (ng/J or lb/million Btu, 24-hour average);
- (3) Percent reduction of the potential combustion concentration of sulfur dioxide (24-hour average) (not required for nitrogen oxides);
- (4) Number of hours of valid emission data collected during each 24-hour daily period;
- (5) Identification of periods when emissions exceed the applicable standards under either § 60.43a or § 60.44a;
- (6) Identification of periods of startup or shutdown that resulted in emissions exceeding the applicable standards under either § 60.43a or § 60.44a;
- (7) Identification of periods when control system malfunction resulted in emissions in excess of applicable nitrogen oxides standards under § 60.44a;
- (8) Identification of "F" factor used for calculations, and type of fuel combusted; and
- (9) Identification of periods when any continuous monitoring systems are not operating and identification of pollutant to be monitored.

(c) 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 conditions of §§ 60.41a(n) and 60.46a(d) were met during each period; and

(2) Listing the:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner's or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from the interconnected reliability council 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 modification.

(d) 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.

(e) 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 standard under § 60.42a(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are submitted to the Administrator each calendar quarter.

(f) 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 (optional).

##### 2.1 Solid fossil fuel.

2.1.1 Sample increment collection. Use ASTM D 2234,\* 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.\* 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 powerplant 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 (percent S) and gross calorific value (GCV) of the solid fuel on a dry basis for each gross sample. Use ASTM 2013\* for sample preparation, ASTM D 3177\* for sulfur analysis, and ASTM D 3173\* for moisture analysis. Use ASTM D 3176\* or D 2015\* for gross calorific value determination.

##### 2.2 Liquid fossil fuel.

\*Use the most recent revision or designation of the ASTM procedure specified.

2.2.1 Sample collection. Use ASTM D 270\* following the practices outlines 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 (shipload, bargeload, 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.

2.2.3 Sample analysis. Determine the percent sulfur content (percent S) and gross calorific value (GCV). Use ASTM D 240\* 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 to pretreatment; percent.

$\%S_o$  = Sulfur content of the product fuel lot on a dry basis; weight percent.

$\%S_i$  = Sulfur dioxide 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 content per unit of heat content of the total fuel lot,  $\%S/GCV$ :

$$\%S/GCV = \frac{\sum_{k=1}^n Y_k (\%S_k/GCV_k)}{\sum_{k=1}^n Y_k}$$

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  $SO_x$  and  $CO_x$  or  $O_2$  oxygen concentrations at the inlet and outlet of the sulfur dioxide control system according to methods specified in the applicable subpart of the regulations.

(NOTE.—The downstream data are used to calculate the  $SO_x$  emission rate. See section 5.) The inlet sulfur dioxide concentration may be determined through fuel analysis (optional, see section 3.3).

3.2 Calculation. Calculate the percent removal efficiency using the following equations as applicable:

$$\%R_{g(O_2)} = 100 \left[ 1 - \frac{SO_{2do} \left( \frac{20.9 - \%O_{2di}}{20.9 - \%O_{2do}} \right)}{SO_{2di}} \right]$$

$$\%R_{g(CO_2)} = 100 \left[ 1 - \left( \frac{SO_{2do}}{SO_{2di}} \times \frac{\%CO_{2di}}{\%CO_{2do}} \right) \right]$$

Where:

$\%R_{g(O_2)}$  = Sulfur dioxide removal efficiency of the sulfur dioxide control device,  $O_2$ -based calculation; percent.

$\%R_{g(CO_2)}$  = Sulfur dioxide removal efficiency of the sulfur dioxide control device,  $CO_2$ -based calculation; percent.

$SO_{2di}$  =  $SO_2$  concentration, dry basis; ppmv.

$\%CO_{2di}$  =  $CO_2$  concentration, dry basis; volume percent.

$\%O_{2di}$  =  $O_2$  concentration, dry basis; volume percent.

i = Inlet.

o = Outlet.

NOTE.—For devices measuring concentration on a wet basis, appropriate equations which account for moisture differences are approved in principle. See the appropriate paragraph in section 5.3. Methods for measuring moisture content are subject to approval of the Administrator.

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 input 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 the 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, fuel lot size is defined as the weight of fuel consumed on one 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 input 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 input 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.

$\%R_g$  = Sulfur dioxide removal efficiency of fuel pretreatment from Section 2; percent. Refer to applicable subpart for definition of applicable averaging period.

## PROPOSED RULES

%R<sub>s</sub>=Sulfur dioxide removal efficiency of sulfur dioxide control device either O<sub>2</sub> or CO<sub>2</sub>-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<sub>2</sub> and O<sub>2</sub> or CO<sub>2</sub> concentrations data obtained in section 3.1. Determine the particulate, NO<sub>x</sub>, and O<sub>2</sub> or CO<sub>2</sub> 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<sub>d</sub>) is the ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted; a wet F factor (F<sub>w</sub>) 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<sub>c</sub>) 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<sub>w</sub> factors and associated emission calculation procedures are not applicable and may not be used after wet scrubbers; F<sub>d</sub> or F<sub>c</sub> 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<sub>c</sub> factors are used.

5.2.1 Average F factors. Table 1 shows average F<sub>d</sub>, F<sub>w</sub>, and F<sub>c</sub> 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:

$$F_d = \frac{227.0(\%H) + 95.7(\%C) + 35.4(\%S) \times 8.6(\%N) - 28.5(\%O)}{GCV}$$

$$F_w = \frac{347.4(\%H) + 95.7(\%C) + 35.4(\%S) + 8.6(\%N) - 28.5(\%O) + 13.0(\%H_2O)**}{GCV_w}$$

$$F_c = \frac{20.0(\%C)}{GCV}$$

For English Units:

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

\*\* The %H<sub>2</sub>O term may be omitted if %H and %O include the unavailable hydrogen and oxygen in the form of H<sub>2</sub>O.

TABLE 1. F FACTORS FOR VARIOUS FUELS

| Fuel-Type               | $F_d$                 |                                 | $F_w$                 |                                 | $F_c$                  |                                |
|-------------------------|-----------------------|---------------------------------|-----------------------|---------------------------------|------------------------|--------------------------------|
|                         | $\frac{dscm}{J}$      | $\frac{dscf}{10^6 \text{ Btu}}$ | $\frac{wscm}{J}$      | $\frac{wscf}{10^6 \text{ Btu}}$ | $\frac{scm}{J}$        | $\frac{scf}{10^6 \text{ Btu}}$ |
| Coal                    |                       |                                 |                       |                                 |                        |                                |
| Anthracite <sup>a</sup> | $2.72 \times 10^{-7}$ | (10140)                         | $2.84 \times 10^{-7}$ | (10680)                         | $0.486 \times 10^{-7}$ | (1810)                         |
| Bituminous <sup>a</sup> | $2.64 \times 10^{-7}$ | (9820)                          | $2.87 \times 10^{-7}$ | (10680)                         | $0.486 \times 10^{-7}$ | (1810)                         |
| Lignite                 | $2.66 \times 10^{-7}$ | (9900)                          | $3.22 \times 10^{-7}$ | (12000)                         | $0.515 \times 10^{-7}$ | (1920)                         |
| Oil <sup>b</sup>        | $2.48 \times 10^{-7}$ | (9220)                          | $2.78 \times 10^{-7}$ | (10360)                         | $0.384 \times 10^{-7}$ | (1430)                         |
| Gas                     |                       |                                 |                       |                                 |                        |                                |
| Natural                 | $2.35 \times 10^{-7}$ | (8740)                          | $2.86 \times 10^{-7}$ | (10650)                         | $0.279 \times 10^{-7}$ | (1040)                         |
| Propane                 | $2.35 \times 10^{-7}$ | (8740)                          | $2.75 \times 10^{-7}$ | (10240)                         | $0.322 \times 10^{-7}$ | (1200)                         |
| Butane                  | $2.35 \times 10^{-7}$ | (8740)                          | $2.80 \times 10^{-7}$ | (10430)                         | $0.338 \times 10^{-7}$ | (1260)                         |
| Wood                    | $2.49 \times 10^{-7}$ | (9280)                          | -----                 | -----                           | $0.494 \times 10^{-7}$ | (1840)                         |
| Wood Bark               | $2.59 \times 10^{-7}$ | (9640)                          | -----                 | -----                           | $0.499 \times 10^{-7}$ | (1860)                         |

<sup>a</sup> As classified according to ASTM D 388-66

<sup>b</sup> Crude, residual, or distillate

$$F_w = 10^6 [5.57(\%H) + 53(\%C) + 0.57(\%S) + 0.14(\%N) + 0.46(\%O) + 0.21(\%H_2O)] \cdot GCV_w$$

$$F_c = \frac{10^6 [0.321(\%C)]}{GCV}$$

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<sub>2</sub>O 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  $F_d$ ,  $F_w$ , and  $F_c$  factors determined by Sections 5.2.1 or 5.2.2 of this section shall be prorated in accordance with the applicable formula as follows:

$$F_d = \sum_{k=1}^n x_k F_{dk} \text{ or}$$

$$F_w = \sum_{k=1}^n x_k F_{wk} \text{ or}$$

$$F_c = \sum_{k=1}^n x_k F_{ck}$$

\*The %H<sub>2</sub>O term may be omitted if %H and %O include the unavailable hydrogen and oxygen in the form of H<sub>2</sub>.

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<sub>2</sub>, and NO<sub>x</sub> 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 <sup>9</sup>          |
| mg/scm                | ng/scm | 10 <sup>6</sup>          |
| lb/scf                | ng/scm | 1.602 × 10 <sup>12</sup> |
| ppm(SO <sub>2</sub> ) | ng/scm | 2.680 × 10 <sup>6</sup>  |
| ppm(NO <sub>x</sub> ) | ng/scm | 1.912 × 10 <sup>6</sup>  |
| ppm(SO <sub>2</sub> ) | lb/scf | 1.660 × 10 <sup>-7</sup> |
| ppm(NO <sub>x</sub> ) | lb/scf | 1.194 × 10 <sup>-7</sup> |

#### 5.3.1 Oxygen-based F factor procedure.

5.3.1.1 Dry basis. When both percent oxygen (%O<sub>2d</sub>) and the pollutant concentration (C<sub>d</sub>) 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<sub>2w</sub>) and the pollutant concentration (C<sub>w</sub>) are measured in the flue gas on a wet basis, the following equations are applicable: (NOTE.—F<sub>w</sub> factors are not applicable after wet scrubbers.)

$$(a) \quad E = C_w F_w \left[ \frac{20.9}{20.9(1 - B_{wa}) - \%O_{2w}} \right]$$

where:

$B_{wa}$  = Proportion by volume of water vapor in the ambient air. Approval may be given for determination of  $B_{wa}$  by on-site instrumental measurement provided that the absolute accuracy of the measurement technique can be demonstrated to be within +0.7 percent water vapor. 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

$$\left( \frac{20.9}{20.9(1 - B_{wa}) - \%O_{2w}} \right)$$

will not be larger than -1.5 percent. However, positive errors, or over-estimation 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 moisture.

(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.

$$(b) \quad E = C_w F_d \left[ \frac{20.9}{20.9(1 - B_{ws}) - \%O_{2w}} \right]$$

where:

$B_{ws}$  = Proportion by volume of water vapor in the stack gas.

This equation is approved in principle. Approval for actual practice is contingent upon demonstrating the ability to accurately determine  $B_{ws}$  such that any absolute error in  $B_{ws}$  will not cause an error of more than ± 1.5 percent in the term:

$$\left( \frac{20.9}{20.9(1 - B_{ws}) - \%O_{2w}} \right)$$

5.3.1.3. Dry/Wet basis. When the pollutant concentration (C<sub>w</sub>) is measured on a wet basis and the oxygen concentration (%O<sub>2w</sub>) or measured on a dry basis, the following equation is applicable:

$$E = \left[ \frac{C_w F_d}{(1 - B_{ws})} \right] \left[ \frac{20.9}{20.9 - \%O_{2d}} \right]$$

NOTE.—See section 5.3.1.2 on the usage of  $B_{ws}$ . When the pollutant concentration (C<sub>d</sub>) is measured on a dry basis and the oxygen concentration (%O<sub>2w</sub>) is measured on a wet basis, the following equation is applicable:

$$E = C_d F_d \left[ \frac{20.9}{20.9 - \left( \frac{\%O_{2w}}{1 - B_{ws}} \right)} \right]$$

**5.3.2 Carbon Dioxide-Based F Factor Procedure.**

**5.3.2.1 Dry Basis.** When both the percent carbon dioxide (%CO<sub>2d</sub>) and the pollutant concentration (C<sub>d</sub>) 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<sub>2w</sub>) and the pollutant concentration (C<sub>w</sub>) 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<sub>w</sub>) is measured on a wet basis and the percent carbon dioxide (%CO<sub>2d</sub>) is measured on a dry basis, the following equation is applicable:

$$E = \left[ \frac{C_w F_c}{(1 - B_{ws})} \right] \left( \frac{100}{\%CO_{2d}} \right)$$

**NOTE.**—See section 5.3.1.2 on the limitation on the usage of B<sub>ws</sub>.

When the pollutant concentration (C<sub>d</sub>) is measured on a dry basis and the percent carbon dioxide (%CO<sub>2w</sub>) 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<sub>2</sub> 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<sub>w</sub> factors shall not be used to determine emission rates from gas turbines because of the injection of steam or to calculate emission rates after wet scrubbers; F<sub>d</sub> or F<sub>c</sub> 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<sub>sg</sub>—Pollutant emission rate from steam generator effluent, ng/J (lb/million Btu).

E<sub>c</sub>—Pollutant emission rate in combined cycle effluent; ng/J (lb/million Btu).

E<sub>gt</sub>—Pollutant emission rate from gas turbine effluent; ng/J (lb/million Btu).

X<sub>sg</sub>—Fraction of total heat input from supplemental fuel fired to the steam generator.

X<sub>gt</sub>—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 direct-firing 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.

**APPENDIX E—[RESERVED]**

5. Appendix E is added to part 60 and reserved.

(Sec. 111, 114, and 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7414, and 7601(a)).  
[FR Doc. 78-26005 Filed 9-18-78; 8:45 am]

**[6560-01]**

[40 CFR Part 60]

[FRL 967-2]

**STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES**

**Public hearing on Proposed Standards for Electric Utility Steam Generating Units**

**AGENCY:** Environmental Protection Agency.

**ACTION:** Hearing on proposed rule.

**SUMMARY:** This document announces a public hearing on the stand-

ards of performance for electric utility steam generating units which are proposed in this issue of the **FEDERAL REGISTER**.

**DATES:** Hearing date: November 29-30, 1978. See Supplementary Information for additional information.

**ADDRESSES:** Hearing held: GSA Auditorium, 18th and F Streets NW., Washington, D.C. See Supplementary Information for additional information.

**FOR FURTHER INFORMATION CONTACT:**

Mr. 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:**

In accordance with section 307(d)(5) of the Clean Air Act, a public hearing on the standards of performance for electric utility steam generating units which are proposed in this issue of the **FEDERAL REGISTER** will be held as follows:

**Date:** November 29-30, 1978.  
**Place:** GSA Auditorium, 18th and F Streets NW., Washington, D.C.  
**Time:** 9 a.m. to 4 p.m.

Persons wishing to make oral presentations, which will be limited to 15 minutes each, should notify EPA by November 17, 1978, by contacting Ms. Shirley Tabler, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5421. 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 Jack R. Farmer, Chief, Standards Development Branch (MD-13), Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711.

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at the U.S. Environmental Protection Agency's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street SW., Washington, D.C. 20460 (Docket No. OAQPS-78-1).

**PURPOSE**

As a result of a suit brought by the Sierra Club, the Agency is under a

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court order to promulgate final regulations within 6 months of today's proposal. This is also the maximum period of time for promulgation permitted by section 307(d)(1) of the Clean Air Act. To comply with the schedule set forth in the court's order, but at the same time to maximize the public's involvement in the rulemaking, the Agency will provide over 14 weeks for public input.

The public involvement period will be structured as follows: Written comments may be submitted by any interested member of the public for a period of 60 days. Following the public comment period, 2 days of hearings will be held. The hearings will be legislative in nature with Agency officials empaneled to receive testimony and ask questions of all witnesses. Persons interested in testifying at the hearing should advise the Agency as instructed above. Though no cross-examination will take place at the hearings, written questions directed at witnesses testifying at the hearing may be submitted to the panel by members of the audience.

It is the expectation of the Agency that the hearing testimony will concentrate on clarifying, supplementing, and rebutting previously submitted written statements. The Agency recognizes that interested persons will require a period of time prior to the

hearing to read the written submissions of other interested parties so that an informed comment may be made at the public hearing. In addition, all written comments received will be placed in the docket (docket No. OAQPS-78-1) as soon after receipt as practicable. All comments received will be on file no later than 2 calendar days after the close of the 60-day comment period. The docket 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.

As required by section 307(d)(5)(iv), the record of the public hearing will remain open for 30 days after completion of the hearing to provide an opportunity for any member of the public to submit rebuttal and supplementary information on the data presented at the hearing. Upon completion of this 30-day period, the record will be closed in order to provide sufficient time for the Administrator to carefully weigh all evidence submitted and to make the final decision on the basis of the formal record.

Dated: September 11, 1978.

DAVID G. HAWKINS,  
Assistant Administrator  
for Air, Noise, and Radiation.

[FR Doc. 78-26006 Filed 9-18-78; 8:45 am]

## RULES AND REGULATIONS

### Title 40—Protection of Environment

#### CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

##### SUBCHAPTER C—AIR PROGRAMS

[FRL 423-6]

### PART 51—REQUIREMENTS FOR THE PREPARATION, ADOPTION AND SUB- MITTAL OF IMPLEMENTATION PLANS

#### Emission Monitoring of Stationary Sources

On September 11, 1974, the Environmental Protection Agency (EPA) proposed revisions to 40 CFR Part 51, Requirements for the Preparation, Adoption, and Submittal of Implementation Plans. EPA proposed to expand § 51.19 to require States to revise their State Implementation Plans (SIP's) to include legally enforceable procedures requiring certain specified categories of existing stationary sources to monitor emissions on a continuous basis. Revised SIP's submitted by States in response to the proposed revisions to 40 CFR 51.19 would have (1) required owners or operators of specified categories of stationary sources to install emission monitoring equipment within one year of plan approval, (2) specified the categories of sources subject to the requirements, (3) identified for each category of sources the pollutant(s) which must be monitored, (4) set forth performance specifications for continuous emission monitoring instruments, (5) required that such instruments meet performance specifications through on-site testing by the owner or operator, and (6) required that data derived from such monitoring be summarized and made available to the State on a quarterly basis.

As a minimum, EPA proposed that States must adopt and implement legally enforceable procedures to require monitoring of emissions for existing sources in the following source categories (but only for sources required to limit emissions to comply with an adopted regulation of the State Implementation Plan):

(a) Coal-fired steam generators of more than 250 million BTU per hour heat input (opacity, sulfur dioxide, oxides of nitrogen and oxygen);

(b) Oil-fired steam generators of more than 250 million BTU per hour heat input (sulfur dioxide, oxides of nitrogen and oxygen). An opacity monitor was required only if an emission control device is needed to meet particulate emission regulations, or if violations of visible emission regulations are noted;

(c) Nitric acid plants (oxides of nitrogen);

(d) Sulfuric acid plants (sulfur dioxide); and

(e) Petroleum refineries' fluid catalytic cracking unit catalyst regenerators (opacity).

Simultaneously, the Agency proposed similar continuous emission monitoring requirements for new sources for each of the previously identified source categories, subject to the provisions of federal New Source Performance Standards set forth in 40 CFR Part 60. Since many of the technical aspects of the two proposals were similar, if not the same, the pro-

posed regulations for Part 51 (i.e., those relating to SIP's and existing sources) included by reference many specific technical details set forth in 40 CFR Part 60, (39 FR 32852).

At the time of the proposal of the continuous emission monitoring regulations in the FEDERAL REGISTER, the Agency invited comments on the proposed rule-making action. Many interested parties submitted comments. Of the 76 comments received, 35 were from electric utility companies, 26 were from oil refineries or other industrial companies, 12 were from governmental agencies, and 3 were from manufacturers and/or suppliers of emission monitors. No comments were received from environmental groups. Further, prior to the proposal of the regulations in the FEDERAL REGISTER, the Agency sought comments from various State and local air pollution control agencies and instrument manufacturers. Copies of each of these comments are available for public inspection at the EPA Freedom of Information Center, 401 M Street, S.W., Washington, D.C. 20460. These comments have been considered, additional information collected and assessed, and where determined by the Administrator to be appropriate, revisions and amendments have been made in formulating these regulations promulgated herein.

*General Discussion of Comments.* In general, the comments received by the Agency tended to raise various objections with specific portions of the regulations. Some misinterpreted the proposed regulations, not realizing that emission monitoring under the proposal was not required unless a source was required to comply with an adopted emission limitation or sulfur in fuel limitation that was part of an approved or promulgated State Implementation Plan. Many questioned the Agency's authority and the need to require sources to use *continuous* emission monitors. Others stated that the proposed regulations were inflationary, and by themselves could not reduce emissions to the atmosphere nor could they improve air quality. A relatively common comment was that the benefits to be derived from the proposed emission monitoring program were not commensurate with the costs associated with the purchase, installation, and operation of such monitors. Many stated that the proposed regulations were not cost-effectively applied and they objected to *all* sources within an identified source category being required to monitor emissions, without regard for other considerations. For instance, some suggested that it was unnecessary to monitor emissions from steam generating plants that may soon be retired from operation, or steam generating boilers that are infrequently used (such as for peaking and cycling operations) or for those sources located in areas of the nation which presently have ambient concentrations better than national ambient air quality standards. This latter comment was especially prevalent in relation to the need for continuous emission monitors designed to measure emissions of oxides of nitrogen. Further, commentators generally suggested that

state and local control agencies, rather than EPA should be responsible for determining which sources should monitor emissions. In this regard, the commentators suggested that a determination of the sources which should install continuous monitors should be made on a case-by-case basis. Almost all objected to the data reporting requirements stating that the proposed requirement of submission of all collected data was excessive and burdensome. Comments from state and local air pollution control agencies in general were similar to those from the utility and industrial groups, but in addition, some indicated that the manpower needed to implement the programs required by the proposed regulations was not available.

*Rationale for Emission Monitoring Regulation.* Presently, the Agency's regulations setting forth the requirements for approvable SIP's require States to have legal authority to require owners or operators of stationary sources to install, maintain, and use emission monitoring devices and to make periodic reports of emission data to the State (40 CFR 51.11(a)(6)). This requirement was designed to partially implement the requirements of Sections 110(a)(2)(F)(ii) and (iii) of the Clean Air Act, which state that implementation plans must provide "requirements for installation of equipment by owners or operators of stationary sources to monitor emissions from such sources", and "for periodic reports on the nature and amounts of such emissions". However, the original implementation plan requirements did not require SIP's to contain legally enforceable procedures mandating continuous emission monitoring and recording. At the time the original requirements were published, the Agency had accumulated little data on the availability and reliability of continuous monitoring devices. The Agency believed that the state-of-the-art was such that it was not prudent to require existing sources to install such devices.

Since that time, much work has been done by the Agency and others to field test and compare various continuous emission monitors. As a result of this work, the Agency now believes that for certain sources, performance specifications for accuracy, reliability and durability can be established for continuous emission monitors of oxygen, carbon dioxide, sulfur dioxide, and oxides of nitrogen and for the continuous measurement of opacity. Accordingly, it is the Administrator's judgment that Sections 110(a)(2)(F)(ii) and (iii) should now be more fully implemented.

The Administrator believes that a sound program of continuous emission monitoring and reporting will play an important role in the effort to attain and maintain national standards. At the present time, control agencies rely upon infrequent manual source tests and periodic field inspections to provide much of the enforcement information necessary to ascertain compliance of sources with adopted regulations. Manual source tests are generally performed on a relatively infrequent basis, such as

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once per year, and in some cases, affected sources probably have never been tested. Manual stack tests are generally performed under optimum operating conditions, and as such, do not reflect the full-time emission conditions from a source. Emissions continually vary with fuel firing rates, process material feed rates and various other operating conditions. Since manual stack tests are only conducted for a relatively short period of time (e.g., one to three hours), they cannot be representative of all operating conditions. Further, frequent manual stack tests (such as conducted on a quarterly or more frequent basis) are costly and may be more expensive than continuous monitors that provide much more information. State Agency enforcement by field inspection is also sporadic, with only occasional inspection of certain sources, mainly for visible emission enforcement.

Continuous emission monitoring and recording systems, on the other hand, can provide a continuous record of emissions under all operating conditions. The continuous emission monitor is a good indicator of whether a source is using good operating and maintenance practices to minimize emissions to the atmosphere and can also provide a valuable record to indicate the performance of a source in complying with applicable emission control regulations. Additionally, under certain instances, the data from continuous monitors may be sufficient evidence to issue a notice of violation. The continuous emission record can also be utilized to signal a plant upset or equipment malfunction so that the plant operator can take corrective action to reduce emissions. Use of emission monitors can therefore provide valuable information to minimize emissions to the atmosphere and to assure that full-time control efforts, such as good maintenance and operating conditions, are being utilized by source operators.

The Agency believes that it is necessary to establish national minimum requirements for emission monitors for specified sources rather than allow States to determine on a case-by-case basis the specific sources which need to continuously monitor emissions. The categories specified in the regulations represent very significant sources of emissions to the atmosphere. States in developing SIPs have generally adopted control regulations to minimize emissions from these sources. Where such regulations exist, the Agency believes that continuous emission monitors are necessary to provide information that may be used to provide an indication of source compliance. Further, it is believed that if the selection of sources on a case-by-case basis were left to the States, that some States would probably not undertake an adequate emission monitoring program. Some State Agencies who commented on the proposed regulations questioned the state-of-the-art of emission monitoring and stated their opinion that the proposed requirements were premature. Therefore, it is the Administrator's judgment that, in order to assure an

adequate nationwide emission monitoring program, minimum emission monitoring requirements must be established.

The source categories affected by the regulations were selected because they are significant sources of emissions and because the Agency's work at the time of the proposal of these regulations in the field of continuous emission monitoring evaluation focused almost exclusively on these source categories. The Agency is continuing to develop data on monitoring devices for additional source categories. It is EPA's intent to expand the minimum continuous emission monitoring requirements from time to time when the economic and technological feasibility of continuous monitoring equipment is demonstrated and where such monitoring is deemed appropriate for other significant source categories.

*Discussion of Major Comments.* Many commentators discussed the various cost aspects of the proposed regulations, specifically stating that the costs of continuous monitors were excessive and inflationary. A total of 47 commentators expressed concern for the cost and/or cost effectiveness of continuous monitors. Further, the Agency's cost estimates for purchasing and installing monitoring systems and the costs for data reduction and reporting were questioned. In many cases, sources provided cost estimates for installation and operation of continuous monitors considerably in excess of the cost estimates provided by the Agency.

In response to these comments, a further review was undertaken by the Agency to assess the cost impact of the regulations. Three conclusions resulted from this review. First, it was determined that the cost ranges of the various emission monitoring systems provided by the Agency are generally accurate for new sources. Discussions with equipment manufacturers and suppliers confirmed this cost information. Approximate investment costs, which include the cost of the emission monitor, installation cost at a new facility, recorder, performance testing, data reporting systems and associated engineering costs are as follows: for opacity, \$20,000; for sulfur dioxide and oxygen or oxides of nitrogen and oxygen, \$30,000; and for a source that monitors opacity, oxides of nitrogen, sulfur dioxide and oxygen, \$55,000. Annual operating costs, which include data reduction and report preparation, system operation, maintenance, utilities, taxes, insurance and annualized capital costs at 10% for 8 years are: \$8,500; \$16,000; and \$30,000 respectively for the cases described above.<sup>(1)</sup>

Secondly, the cost review indicated that the cost of installation of emission monitors for existing sources could be considerably higher than for new sources because of the difficulties in providing access to a sampling location that can provide a representative sample of emissions. The cost estimates provided by the Agency in the proposal were specifically developed for new sources whose installation costs are relatively stable since provisions for monitoring equipment can be incorporated at the time of plant design. This feature is not available for ex-

isting sources, hence higher costs generally result. Actual costs of installation at existing sources may vary from one to five times the cost of normal installation at new sources, and in some cases even higher costs can result. For example, discussions with instrument suppliers indicate that a typical cost of installation of an opacity monitor on an existing source may be two to three times the purchase price of the monitor. Difficulties also exist for installation of gaseous monitors at existing sources.

It should be noted that these installation costs include material costs for scaffolding, ladders, sampling ports and other items necessary to provide access to a location where source emissions can be measured. It is the Agency's opinion that such costs cannot be solely attributed to these continuous emission monitoring regulations. Access to sampling locations is generally necessary to determine compliance with applicable state or local emission limitations by routine manual stack testing methods. Therefore, costs of providing access to a representative sampling location are more directly attributed to the cost of compliance with adopted emission limitations, than with these continuous emission monitoring regulations.

Lastly, the review of cost information indicated that a number of commentators misinterpreted the extent of the proposed regulations, thereby providing cost estimates for continuous monitors which were not required. Specifically, all commentators did not recognize that the proposed regulations required emission monitoring for a source only if an applicable State or local emission limitation of an approved SIP affected such a source. For example, if the approved SIP did not contain an adopted control regulation to limit oxides of nitrogen from steam-generating, fossil fuel-fired boilers of a capacity in excess of 250 million BTU per hour heat input, then such source need not monitor oxides of nitrogen emissions. Further, some utility industry commentators included the costs of continuous emission monitors for sulfur dioxide. The proposed regulations, however, generally allowed the use of fuel analysis by specified ASTM procedures as an alternative which, in most cases, is less expensive than continuous monitoring. Finally, the proposed regulations required the continuous monitoring of oxygen in the exhaust gas only if the source must otherwise continuously monitor oxides of nitrogen or sulfur dioxide. Oxygen information is used solely to provide a correction for excess air when converting the measurements of gaseous pollutants concentrations in the exhaust gas stream to units of an applicable emission limitation. Some commentators did not recognize this point (which was not specifically stated in the proposed regulations) and provided cost estimates for oxygen monitors when they were not required by the proposed regulations.

While not all commentators' cost estimates were correct, for various reasons noted above, it is clear that the costs associated with implementing these emission monitoring regulations are sig-

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nificant. The Administrator, however, believes that the benefits to be derived from emission monitoring are such that the costs are not unreasonable. The Administrator does, however, agree with many commentators that the proposed regulations, in some cases, were not applied cost-effectively and, as such, the regulations promulgated herein have been modified to provide exemptions to certain sources from these minimum requirements.

One comment from another Federal Agency concerned the time period that emissions are to be averaged when reporting excess emissions. Specifically, the commentator assumed that the emission control regulations that have been adopted by State and local agencies were generally designed to attain annual ambient air quality standards. As such, the commentator pointed out that short-term emission levels in excess of the adopted emission standard should be acceptable for reasonable periods of time.

The Administrator does not agree with this rationale for the following reasons. First, it is not universally true that annual ambient standards were the design basis of emission control regulations. In many cases, reductions to attain short-term standards require more control than do annual standards. Even if the regulations were based upon annual standards, allowing excess emissions of the adopted emission control regulation on a short-term basis could cause non-compliance with annual standards. More importantly, however, a policy of legally allowing excesses of adopted control regulations would in effect make the current emission limitation unenforceable. If the suggestion were implemented, a question would arise as to what is the maximum emission level that would not be considered an excess to the adopted regulation. The purpose of the adopted emission limitation was to establish the acceptable emission level. Allowing emissions in excess of that adopted level would cause confusion, ambiguity, and in many cases could result in an unenforceable situation. Hence the Administrator does not concur with the commentator's suggestion.

**Modifications to the Proposed Regulations.** The modification to the regulations which has the most significant impact involves the monitoring requirements for oxides of nitrogen at fossil fuel-fired steam generating boilers and at nitric acid plants. Many commentators correctly noted that the Agency in the past (June 8, 1973, 38 FR 15174) had indicated that the need for many emission control regulations for oxides of nitrogen were based upon erroneous data. Such a statement was made after a detailed laboratory analysis of the reference ambient measurement method for nitrogen dioxide revealed the method to give false measurements. The sampling technique generally indicated concentrations of nitrogen dioxide higher than actually existed in the atmosphere. Since many control agencies prior to that announcement had adopted emission regulations that were determined to be needed based upon

these erroneous data, and since new data, collected by other measurement techniques, indicated that in most areas of the nation such control regulations were not necessary to satisfy the requirements of the SIP, the Agency suggested that States consider the withdrawal of adopted control regulations for the control of oxides of nitrogen from their SIP's (May 8, 1974, 39 FR 16344). In many States, control agencies have not taken action to remove these regulations from the SIP. Hence, the commentators pointed out that the proposed regulations to require continuous emission monitors on sources affected by such regulations is generally unnecessary.

Because of the unique situation involving oxides of nitrogen control regulations, the Administrator has determined that the proposed regulations to continuously monitor oxides of nitrogen emissions may place an undue burden on source operators, at least from a standpoint of EPA specifying minimum monitoring requirements. The continuous emission monitoring requirements for such sources therefore have been modified. The final regulations require the continuous emission monitoring of oxides of nitrogen only for those sources in Air Quality Control Regions (AQCR's) where the Administrator has specifically determined that a control strategy for nitrogen dioxide is necessary. At the present time such control strategies are required only for the Metropolitan Los Angeles Intrastate and the Metropolitan Chicago Interstate AQCR's.

It should be noted that a recent compilation of valid nitrogen dioxide air quality data suggests that approximately 14 of the other 245 AQCR's in the nation may need to develop a control strategy for nitrogen dioxide. These AQCR's are presently being evaluated by the Agency. If any additional AQCR's are identified as needing a control strategy for nitrogen dioxide at that time, or any time subsequent to this promulgation, then States in which those AQCR's are located must also revise their SIP's to require continuous emission monitoring for oxides of nitrogen for specified sources. Further, it should be noted that the regulations promulgated today are minimum requirements, so that States, if they believe the control of oxides of nitrogen from sources is necessary may, as they deem appropriate, expand the continuous emission monitoring requirements to apply to additional sources not affected by these minimum requirements.

Other modifications to the proposed regulation resulted from various comments. A number of commentators noted that the proposed regulations included some sources whose emission impact on air quality was relatively minor. Specifically, they noted that fossil fuel-fired steam generating units that were used solely for peaking and cycling purposes should be exempt from the proposed regulations. Similarly, some suggested that smaller sized units, particularly steam-generating units less than 2,500 million BTU per hour heat input, should also be exempted. Others pointed out that

units soon to be retired from operation should not be required to install continuous monitoring devices and that sources located in areas of the nation that already have air quality better than the national standards should be relieved of the required monitoring and reporting requirements. The Agency has considered these comments and has made the following judgments.

In relation to fossil fuel-fired steam generating units, the Agency has determined that such units that have an annual boiler capacity factor of 30% or less as currently defined by the Federal Power Commission shall be exempt from the minimum requirements for monitoring and reporting. Industrial boilers used at less than 30% of their annual capacity, upon demonstration to the State, may also be granted an exemption from these monitoring requirements. The rationale for this exemption is based upon the fact that all generating units do not produce power at their full capacity at all times. There are three major classifications of power plants based on the degree to which their rated capacity is utilized on an annual basis. Baseload units are designed to run at near full capacity almost continuously. Peaking units are operated to supply electricity during periods of maximum system demand. Units which are operated for intermediate service between the extremes of baseload and peaking are termed cycling units.

Generally accepted definitions term units generating 60 percent or more of their annual capacity as baseload, those generating less than 20 percent as peaking and those between 20 and 60 percent as cycling. In general, peaking units are older, smaller, of lower efficiency, and more costly to operate than base load or cycling units. Cycling units are also generally older, smaller and less efficient than base load units. Since the expected life of peaking units is relatively short and total emissions from such units are small, the benefits gained by installing monitoring instruments are small in comparison to the cost of such equipment. For cycling units, the question of cost-effectiveness is more difficult to ascertain. The units at the upper end of the capacity factor range (i.e., near 60% boiler capacity factor) are candidates for continuous emission monitoring while units at the lower end of the range (i.e., near 20% boiler capacity factor) do not represent good choices for continuous monitors. Based upon available emission information, it has been calculated that fossil fuel-fired steam generating plants with a 30% or less annual boiler capacity factor contribute approximately less than 5% of the total sulfur dioxide from all such power plants. (2) Hence, the final regulations do not affect any boiler that has an annual boiler capacity factor of less than 30%. Monitoring requirements will thus be more cost effectively applied to the newer, larger, and more efficient units that burn a relatively larger portion of the total fuel supply.

Some commentators noted that the age of the facility should be considered in relation to whether a source need com-

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ply with the proposed regulations. For fossil fuel-fired steam generating units, the exemption relating to the annual boiler capacity factor previously discussed should generally provide relief for older units. It is appropriate, however, that the age of the facility be considered for other categories of sources affected by the proposed regulations. As such, the final regulations allow that any source that is scheduled to be retired within five years of the inclusion of monitoring requirements for the source in Appendix P need not comply with the minimum emission monitoring requirements promulgated herein. In the Administrator's judgment, the selection of five years as the allowable period for this exemption provides reasonable relief for those units that will shortly be retired. However, it maintains full requirements on many older units with a number of years of service remaining. In general, older units operate less efficiently and are less well controlled than newer units so that emission monitoring is generally useful. The exemption provided in the final regulations effectively allows such retirees slightly more than a two-year period of relief, since the schedule of implementation of the regulations would generally require the installation of emission monitors by early 1978. States must submit, for EPA approval, the procedures they will implement to use this provision. States are advised that such exemptions should only be provided where a bona fide intent to cease operations has been clearly established. In cases where such sources postpone retirement, States shall have established procedures to require such sources to monitor and report emissions. In this regard, it should be noted that Section 113(c)(2) of the Act provides that any person who falsifies or misrepresents a record, report or other document filed or required under the Act shall, upon conviction, be subject to fine or imprisonment, or both.

A further modification to the proposed regulations affects the minimum size of the units within each of the source categories to which emission monitoring and reporting shall be required. As suggested by many commentators, the Agency has investigated the cost effectiveness of requiring all units within the identified source categories to install emission monitors. Each pollutant for each source category identified in the proposed regulations was evaluated. For fossil fuel-fired steam generating units, the proposal required compliance for all boilers with 250 million BTU per hour heat input, or greater. For opacity, the proposed regulations required emission monitoring for all coal-fired units, while only those oil-fired units that had been observed as violators of visible emission regulations or must use an emission control device to meet particulate matter regulations were required to install such devices. Gas-fired units were exempted by the proposed regulations.

After investigating the particulate emission potential of these sources, it has been determined that no modification in

the size limitation for boilers in relation to opacity is warranted. The rationale for this judgment is that the smaller-sized units affected by the proposed regulation tend to be less efficiently operated or controlled for particulate matter than are the larger-sized units. In fact, smaller units generally tend to emit more particulate emissions on an equivalent fuel basis than larger-sized units. (2) Because of the potential of opacity regulation violations, no modifications have been made to the regulations as to the size of steam generating boilers that must measure opacity.

Emissions of oxides of nitrogen from boilers are a function of the temperature in the combustion chamber and the cooling of the combustion products. Emissions vary considerably with the size and the type of unit. In general, the larger units produce more oxides of nitrogen emissions. The Agency therefore finds that the minimum size of a unit affected by the final regulations can be increased from 250 to 1,000 million BTU per hour heat input, without significantly reducing the total emissions of oxides of nitrogen that would be affected by monitoring and reporting requirements. Such a modification would have the effect of exempting approximately 56% of the boilers over 250 million BTU per hour heat input capacity, on a national basis, while maintaining emission monitoring and reporting requirements for approximately 78% of the potential oxides of nitrogen emissions from such sources. (2) Further, in the 2 AQCR's where the Administrator has specifically called for a control strategy for nitrogen dioxide, the boilers affected by the regulation constitute 50% of the steam generators greater than 250 million BTU per hour heat input, yet they emit 80% of the nitrogen oxides from such steam generators in these 2 AQCR's. (2)

Also, certain types of boilers or burners, due to their design characteristics, may on a regular basis attain emission levels of oxides of nitrogen well below the emission limitations of the applicable plan. The regulations have been revised to allow exemption from the requirements for installing emission monitoring and recording equipment for oxides of nitrogen when a facility is shown during performance tests to operate with oxides of nitrogen emission levels 30% or more below the emission limitation of the applicable plan. It should be noted that this provision applies solely to oxides of nitrogen emissions rather than other pollutant emissions, since oxides of nitrogen emissions are more directly related to boiler design characteristics than are other pollutants.

Similar evaluations were made for nitric acid plants, sulfuric acid plants and catalytic cracking unit catalyst regenerators at petroleum refineries. For each of these industries it was found that modifications to the proposed regulations could be made to increase the minimum size of the units affected by the proposed regulations without significantly decreasing the total emissions of various

pollutants that would be affected by these monitoring and reporting requirements. Specifically, for nitric acid plants it was found that by modifying the proposed regulations to affect only those plants that have a total daily production capacity of 300 tons or more of nitric acid (rather than affecting all facilities as proposed) that approximately 79% of the nitric acid production on a national basis would be affected by the provisions of these monitoring and reporting requirements. On the other hand, such a modification reduces the number of monitors required for compliance with these regulations by approximately 46%. (2) At the present time, only nitric acid plants in AQCR's where the Administrator has specifically called for a control strategy for nitrogen dioxide will be candidates for continuous emission monitoring requirements for the reasons mentioned previously. In the 2 AQCR's where such a control strategy has been called for, there is only one known nitric acid plant and that is reported to be less than 300 tons per day production capacity—hence no nitric acid plants at the present time will be affected by these monitoring requirements.

Similarly, evaluations of sulfuric acid plants and catalytic cracking catalyst regenerators at petroleum refineries resulted in the conclusion that minimum size limitations of 300 tons per day production rate at sulfuric acid plants, and 20,000 barrels per day of fresh feed to any catalytic cracking unit at petroleum refineries could be reasonably established. Such modifications exempt approximately 37% and 39% respectively of such plants on a national basis from these emission monitoring and reporting requirements, while allowing about 9% of the sulfur dioxide emissions from sulfuric acid plants and 12% of the particulate matter emissions from catalytic cracking units to be emitted to the atmosphere without being measured and reported. (2) The Agency believe that such modifications provide a reasonable balance between the costs associated with emission monitoring and reporting, and the need to obtain such information.

A number of commentators suggested that sources be exempt from the proposed emission monitoring regulations if such sources are located within areas of the nation that are already attaining national standards. The Administrator does not believe that such an approach would be consistent with Section 110 of the Clean Air Act, which requires continued maintenance of ambient standards after attainment. In many areas, the standards are being attained only through effective implementation of emission limitations. Under the Clean Air Act, continued compliance with emission limitations in these areas is just as important as compliance in areas which have not attained the standards.

Another major comment concerned the proposed data reporting requirements. Thirty-four (34) commentators expressed concern at the amount of data which the proposed regulations required to be recorded, summarized, and submit-

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ted to the State. It was generally indicated by the commentators that the data reporting requirements were excessive. Commentors questioned the purpose of reporting all measured data while some State agencies indicated they have limited resources to handle such information. EPA believes that, in some cases, the commentators misconstrued the data reporting requirements for existing sources. In light of each of these comments, the final regulations, with respect to the data reporting requirements for gaseous pollutants and opacity, have been modified.

For gaseous emissions, the proposed regulations required the reporting of all one-hour averages obtained by the emission monitor. Because of the comments on this provision, the Agency has reexamined the proposed data reporting requirements. As a result, the Agency has determined that only information concerning emissions in excess of emission limitations of the applicable plan is necessary to satisfy the intent of these regulations. Therefore, the data reporting requirements for gaseous pollutants have been modified. The final regulations require that States adopt procedures that would require sources to report to the State on emission levels in excess of the applicable emission limitations (i.e., excess emissions) for the time period specified in the regulation with which compliance is determined. In other words, if an applicable emission limitation required no more than 1.0 pounds per hour SO<sub>2</sub> to be emitted for any two-hour averaging period, the data to be reported by the source should identify the emission level (i.e., emissions stated in pounds per hour) averaged over a two-hour time period, for periods only when this emission level was in excess of the 1.0 pounds per hour emission limitation. Further, sources shall be required to maintain a record of all continuous monitoring observations for gaseous pollutants (and opacity measurements) for a period of two years and to make such data available to the State upon request. The final regulations have also been amended to add a provision to require sources to report to the State on the apparent reason for all noted violations of applicable regulations.

The proposed data reporting requirements for opacity have also been modified. Upon reconsideration of the extent of the data needed to satisfy the intent of these regulations, it is the Administrator's judgment that for opacity States must obtain excess emission measurements during each hour of operation. However, before determining excess emissions, the number of minutes generally exempted by State opacity regulations should be considered. For example, where a regulation allows two minutes of opacity measurements in excess of the standard, the State need only require the source to report all opacity measurements in excess of the standard during any one hour, minus the two-minute exemption. The excess measurements shall be reported in actual per cent opacity averaged for

one clock minute or such other time period deemed appropriate by the State. Averages may be calculated either by arithmetically averaging a minimum of 4 equally spaced data points per minute or by integration of the monitor output.

Some commentators raised questions concerning the provisions in the proposed regulations which allow the use of fuel analysis for computing emissions of sulfur dioxide in lieu of installing a continuous monitoring device for this pollutant. Of primary concern with the fuel analysis approach among the commentators was the frequency of the analysis to determine the sulfur content of the fuel. However, upon inspection of the comments by the Agency, a more significant issue has been uncovered. The issue involves the determination of what constitutes excess emissions when a fuel analysis is used as the method to measure source emissions. For example, the sulfur content varies significantly within a load of coal, i.e., while the average sulfur content of a total load of coal may be within acceptable limits in relation to a control regulation which restricts the sulfur content of coal, it is probable that portions of the coal may have a sulfur content above the allowable level. Similarly, when fuel oils of different specific gravities are stored within a common tank, such fuel oils tend to stratify and may not be a homogeneous mixture. Thus, at times, fuel oil in excess of allowable limits may be combusted. The question which arises is whether the combustion of this higher sulfur coal or oil is a violation of an applicable sulfur content regulation. Initial investigations of this issue have indicated a relative lack of specificity on the subject.

The Agency is confronted with this problem not only in relation to specifying procedures for the emission reporting requirements for existing sources but also in relation to enforcement considerations for new sources affected by New Source Performance Standards. At this time, a more thorough investigation of the situation in necessary prior to promulgation of procedures dealing with fuel analysis for both oil and coal. At the conclusion of this investigation, the Agency will set forth its findings and provide guidance to State and local control agencies on this issue. In the meantime, the portion of the proposed regulations dealing with fuel analysis is being withheld from promulgation at this time. As such, States shall not be required to adopt provisions dealing with emission monitoring or reporting of sulfur dioxide emissions from those sources where the States may choose to allow the option of fuel analysis as an alternative to sulfur dioxide monitoring. However, since the fuel analysis alternative may not be utilized by a source that has installed sulfur dioxide control equipment (scrubbers), States shall set forth legally enforceable procedures which require emission monitors on such sources, where these emission monitoring regulations otherwise require their installation.

*Other Modifications to Proposed Regulations.* In addition to reducing the number of monitors required under the

proposed regulations, a number of modifications to various procedures in the proposed regulations have been considered and are included in the final regulations. One modification which has been made is the deletion of the requirement to install continuous monitors at "the most representative" location. The final regulations require the placement of an emission monitor at "a representative" location in the exhaust gas system. In many cases "the most representative" location may be difficult to locate and may be inaccessible without new platforms, ladders, etc., being installed. Further, other representative locations can provide adequate information on pollutant emissions if minimum criteria for selection of monitoring locations are observed. Guidance in determining a representative sampling location is contained within the Performance Specification for each pollutant monitor in the emission monitoring regulations for New Source Performance Standards (Appendix B, Part 60 of this Chapter). While these criteria are designed for new sources, they are also useful in determining representative locations for existing sources.

A further modification to the proposed regulation is the deletion of the requirement for new performance tests when continuous emission monitoring equipment is modified or repaired. As proposed, the regulation would have required a new performance test whenever any part of the continuous emission monitoring system was replaced. This requirement was originally incorporated in the regulations to assure the use of a well-calibrated, finely tuned monitor. Commentors pointed out that the requirement of conducting new performance tests whenever any part of an instrument is changed or replaced is costly and in many cases not required. Upon evaluation of this comment, the Administrator concurs that performance tests are not required after each repair or replacement to the system. Appropriate changes have been made to the regulations to delete the requirements for new performance tests. However, the final regulations require the reporting of the various repairs made to the emission monitoring system during each quarter to the State. Further, the State must have procedures to require sources to report to the State on a quarterly basis information on the amount of time and the reason why the continuous monitor was not in operation. Also the State must have legally enforceable procedures to require a source to conduct a new performance test whenever, on the basis of available information, the State deems such test is necessary.

The time period proposed for the installation of the required monitoring system, i.e., one year after plan approval, was thought by 21 commentators to be too brief, primarily because of lack of available instruments, the lack of trained personnel and the time available for installation of the required monitors. Equipment suppliers were contacted by the Agency and they confirmed the availability of emission monitors. However,

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the Administrator has determined that the time necessary for purchase, installation and performance testing of such monitors may require more than one year for certain installations, especially where gaseous monitors are required. In order to provide sources with ample time, the Agency has modified the final regulations to allow States to adopt procedures that will provide sources 18 months after the approval or promulgation of the revised SIP to satisfy the installation and performance testing procedures required by these continuous monitoring regulations. A provision is also included to allow, on a case-by-case basis, additional extensions for sources where good faith efforts have been undertaken to purchase and install equipment, but where such installation cannot be accomplished within the time period prescribed by the regulations.

A number of State and local agencies also commented on the lack of time provided sources to install the monitors required by the proposed regulations. These agencies also indicated that they must acquire sufficient skilled manpower to implement the regulations, such as personnel to provide guidance to sources, to monitor performance tests and to analyze the emission data that are to be submitted by the sources. Further, some State agencies indicated that more than six months was needed to develop the necessary plan revisions. Most State agencies who commented stated that one year should be provided to allow States to revise their SIP's. The Administrator is aware of the various priorities which confront State and local agencies at this time (e.g., compliance schedules, enforcement actions, litigation proceedings, re-evaluation of adequacy of SIP's to attain and maintain national standards, etc.) and, as such, believes that a six-month postponement in the submittal of plan revisions to require emission monitoring and reporting is justified and prudent. Hence, States must submit plan revisions to satisfy the requirements of this section within one year of promulgation of these regulations in the *FEDERAL REGISTER*. However, States are advised that such plan revisions may be submitted any time prior to the final date, and are encouraged to do so where possible.

The proposed regulations provided the States with the option of allowing sources to continue to use emission monitoring equipment that does not meet performance specifications set forth in the regulations for up to five years from the date of approval of the State regulations or EPA promulgation. Some commenters asked that this provision be extended indefinitely. In some cases they indicated they had recently purchased and had already installed monitoring systems which were only marginally away from meeting the applicable performance specifications. The Agency believes, however, that such a modification to the proposed regulations should not be allowed. It is believed that such a provision would result in inadequate monitoring systems being maintained after their useful life has ended. Though some monitoring sys-

tems will probably last longer than five years, it is believed that this time period will provide adequate time to amortize the cost of such equipment. In cases where existing emission monitors are known not to provide reasonable estimates of emissions, States should consider more stringent procedures to provide a more speedy retirement of such emission monitoring systems.

Some commentors raised the question of whether existing oxygen monitors which are installed in most fossil fuel-fired steam generating boilers to monitor excess oxygen for the purposes of combustion control could be used to satisfy the requirement for monitoring oxygen under the proposal. Upon investigation, it has been determined that, in some cases, such oxygen monitors may be used provided that they are located so that there is no influx of dilution air between the oxygen monitor and the continuous pollutant monitor. In some cases, it may be possible to install the continuous monitoring device at the same location as the existing oxygen monitor. Care should be taken, however, to assure that a representative sample is obtained. Because of the various possibilities that may arise concerning the usefulness of existing oxygen monitors, the State should determine, after a case-by-case review, the acceptability of existing oxygen monitors.

Another technical issue which was raised suggested that continuous emission monitors which provide direct measurements of pollutants in units comparable to the emission limitations and other devices not specifically identified in the proposed regulations are available for purchase and installation. The Agency is aware that various monitoring systems exist but has not as yet determined specific performance specifications for these monitoring systems that are directly applicable to the source categories covered by these regulations. However, it is not EPA's intent to deny the use of any equipment that can be demonstrated to be reliable and accurate. If monitors can be demonstrated to provide the same relative degree of accuracy and durability as provided by the performance specifications in Appendix B of Part 60, they shall generally be acceptable to satisfy the requirements of these regulations under Section 3.9 of Appendix P. Further, where alternative procedures (e.g., alternate procedures for conversion of data to units of applicable regulations) can be shown by the State to be equivalent to the procedures set forth in Appendix P of these regulations, then such alternate procedures may be submitted by the State for approval by EPA. Section 3.9 of Appendix P identifies certain examples where alternative emission monitoring systems or alternative procedures will generally be considered by the Agency for approval.

It should be noted that some sources may be unable to comply with the regulations because of technical difficulties, (e.g., the presence of condensed water vapor in the flue gas), physical limitations of accessibility at the plant facility,

or, in other cases, because of extreme economic hardship. States should use their judgment in implementing these requirements in such cases. Section 6 of Appendix P of this Part provides various examples where the installation of continuous emission monitors would not be feasible or reasonable. In such cases alternate emission monitoring (and reporting) by more routine methods, such as manual stack testing, must be required. States in preparing their revised SIP must set forth and describe the criteria they will use to identify such unusual cases, and must further describe the alternative procedures they will implement to otherwise satisfy the intent of these regulations. States are advised that this provision is intended for unusual cases, and, as such, should not be widely applied.

It was pointed out by some commentors that carbon dioxide monitors could probably be used in lieu of oxygen monitors to provide information to convert emission data to the units of the applicable State regulation. Detailed discussion of the technical merits and limitations of this approach is discussed in the Preamble to the Part 60 Regulations. As pointed out in that Preamble, such monitors may be used in certain situations. Modifications have therefore been made to the Part 51 regulations to allow the use of such monitors which include references to technical specifications contained in Part 60 for carbon dioxide monitors. Also, the cycling time for oxygen monitors has been changed from one hour to 15 minutes to correspond to the specification in Part 60. The difference between cycling times in the two proposals was an oversight. The cycling time for carbon dioxide monitors will also be 15 minutes as in Part 60.

A number of other miscellaneous technical comments were also received. Commentors indicated that the proposed exemption for opacity monitoring requirements that may be granted to oil-fired and gas-fired steam generators should also apply to units burning a combination of these fuels. The Administrator concurs with this suggestion and an exemption for such sources burning oil and gas has been provided in the final regulations subject to the same restrictions as are imposed on oil-fired steam generators.

As previously indicated, the regulations for emission monitoring for existing sources refer in many cases to the specific performance specifications set forth in the emission monitoring regulations for new sources affected by Part 60. Many of the comments received on the proposed regulations in effect pointed to issues affecting both proposals. In many cases, more specific technical issues are discussed in the Preamble to the Part 60 Regulations and as such the reader is referred to that Preamble. Specifically, the Part 60 Preamble addresses the following topics: data handling and reporting techniques; requirements for reporting repairs and replacement parts used; location of monitoring instruments; changes to span requirements, operating

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frequency requirements, sulfuric acid and nitric acid plant conversion factors; and, for opacity monitoring equipment, changes in the cycling time and in alignment procedures. The reader is cautioned, however, that specific reference to regulations in the Part 60 Preamble is strictly to federal New Source Performance Regulations rather than State and local control agency regulations which affect existing sources and which are part of an applicable plan.

In addition to the many technical comments received, a number of legal issues were raised. Several commentors questioned EPA's statutory authority to promulgate these regulations and pointed out other alleged legal defects in the proposal. The Administrator has considered these comments, and has found them unpersuasive.

One commentor argued that new 40 CFR 51.19(e) will require "revisions" to existing state plans; that "revisions" may be called for under Section 110(a)(2)(H) of the Clean Air Act only where EPA has found that there are "improved or more expeditious methods" for achieving ambient standards or that a state plan is "substantially inadequate" to achieve the standards; that the new regulation is based upon neither of these findings; and that therefore there is no statutory authority for the regulation. This argument fails to take cognizance of Section 110(a)(2)(F)(ii) of the Act, which mandates that all state implementation plans contain self-monitoring requirements. The fact that EPA originally accepted plans without these requirements because of substantial uncertainty as to the reliability of self-monitoring equipment does not negate the mandate of the statute.

In essence, new § 51.19(e) does not call for "revisions" as contemplated by the Act, but for supplements to the original plans to make them complete. At any rate, it is the Administrator's judgment that the new self-monitoring requirements will result in a "more expeditious" achievement of the ambient standards. Since these requirements are valuable enforcement tools and indicators of malfunctions, they should lead to a net decrease in emissions.

Other commentors argued that even if EPA has statutory authority to require self-monitoring, it has no authority to impose specific minimum requirements for state plans, to require "continuous" monitoring, or to require monitoring of oxygen, which is not a pollutant. These comments fail to consider that a basic precept of administrative law is that an agency may fill in the broad directives of legislation with precise regulatory requirements. More specifically, the Administrator has authority under Section 301(a) of the Clean Air Act to promulgate "such regulations as are necessary to carry out his functions under the Act". Courts have long upheld the authority of agencies to promulgate more specific requirements than are set forth in enabling legislation, so long as the requirements are reasonably related to the purposes of the legislation. Since the Act

requires self-monitoring without further guidance, EPA surely has the authority to set specific requirements in order to carry out its function of assuring that the Act is properly implemented.

In EPA's judgment, the requirements set forth in § 51.19(e) are necessary to assure that each state's self-monitoring program is sufficient to comply with the Act's mandate. The fact that oxygen and carbon dioxide are not air pollutants controlled under the Act is legally irrelevant, since in EPA's judgment, they must be monitored in order to convert measured emission data to units of emission standards.

Other commentors have argued that the self-monitoring requirements violate the protection against self-incrimination provided in the Fifth Amendment to the U.S. Constitution, and that the information obtained from the monitoring is so unreliable as to be invalid evidence for use in court.

There are two reasons why the self-incrimination argument is invalid. First, the self-incrimination privilege does not apply to corporations, and it is probable that a great majority of the sources covered by these requirements will be owned by corporations. Secondly, courts have continually recognized an exception to the privilege for "records required by law", such as the self-monitoring and reporting procedures which are required by the Clean Air Act. As to the validity of evidence issue, in EPA's opinion, the required performance specifications will assure that self-monitoring equipment will be sufficiently reliable to withstand attacks in court.

Finally, some comments reflected a misunderstanding of EPA's suggestion that states explore with counsel ways to draft their regulations so as to automatically incorporate by reference future additions to Appendix P and avoid the time-consuming plan revision process. (EPA pointed out that public participation would still be assured, since EPA's proposed revisions to Appendix P would always be subject to public comment on a nation-wide basis.)

EPA's purpose was merely to suggest an approach that a state may wish to follow if the approach would be legal under that state's law. EPA offers no opinion as to whether any state law would allow this. Such a determination is up to the individual states.

*Summary of Revisions and Clarifications to the Proposed Regulations.* Briefly, the revisions and clarifications to the proposed regulations include:

(1) A clarification to indicate that continuous emission monitors are not required for sources unless such sources are subject to an applicable emission limitation of an approved SIP.

(2) A revision to require emission monitors for oxides of nitrogen in only those AQCR's where the Administrator has specifically called for a control strategy for nitrogen dioxide.

(3) A revision to include a general provision to exempt any source that clearly demonstrates that it will cease operation

within five years of the inclusion of monitoring requirements for the source in Appendix P.

(4) Revisions to exempt smaller-sized sources and infrequently used sources within the specified source categories.

(5) A revision to the data reporting requirements to require the submittal by the source of the State, emission data in excess of the applicable emission limitation for both opacity and gaseous pollutants, rather than all measured data, as proposed. A provision has been added to require information on the cause of all noted violations of applicable regulations.

(6) A clarification to indicate that the continuous monitoring of oxygen is not required unless the continuous monitoring of sulfur dioxide and/or nitrogen oxides emissions is required by the applicable SIP.

(7) A revision to allow the placement of continuous emission monitors at "a representative location" on the exhaust gas system rather than at "the most representative location" as required by the proposed regulations.

(8) A revision to delete the requirements of new performance tests each time the continuous monitoring equipment is repaired or modified. However, a new provision is included to require that a report of all repairs and maintenance performed during the quarter shall be reported by the source to the State.

(9) A modification to provide sources 18 months rather than one year after approval or promulgation of the revised SIP to comply with the continuous monitoring regulations adopted by the States.

(10) A modification to provide States one year, rather than the six months after the promulgation of these regulations in the FEDERAL REGISTER to submit plan revisions to satisfy the requirements promulgated herein.

*Requirements of States.* States shall be required to revise their SIP's by October 6, 1976 to include legally enforceable procedures to require emission monitoring, recording and reporting, as a minimum for those sources specified in the regulations promulgated herein. While minimum requirements have been established, States may, as they deem appropriate, expand these requirements.

The regulations promulgated herein have been revised in light of the various comments to generally provide a more limited introduction into this new methodology. Cooperation among affected parties, i.e., State and local control agencies, sources, instrument manufacturers and suppliers, and this Agency is necessary to move successfully forward in these areas of emission monitoring and reporting prescribed in the Clean Air Act. Assistance can be obtained from the EPA Regional Offices in relation to the technical and procedural aspects of these regulations.

Copies of documents referenced in this Preamble are available for public inspection at the EPA Freedom of Information Center, 401 M Street, S.W., Washington, D.C. 20460. The Agency has not prepared an environmental impact statement for these regulations since they

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were proposed (September 11, 1974) prior to the effective date for requiring voluntary environmental impact statements on EPA's regulatory actions (see 39 FR 16186, May 7, 1974).

The regulations set forth below are promulgated under the authority of sections 110(a)(2)(F)(ii)-(iii) and 301(a) of the Clean Air Act, as amended (42 U.S.C. 1857c-5(a)(2)(F)(ii)-(iii), 1857g(a)) and are effective November 5, 1975.

Dated: September 23, 1975.

JOHN QUARLES,  
Acting Administrator.

### REFERENCES

1. Jenkins, R. E. Strategies and Air Standards Division, OAQPS, EPA. Memo to R. L. Ajax, Emission Standards and Engineering Division, OAQPS, EPA, Emission Monitoring Costs, February 27, 1975.
2. Young, D. E. Control Programs Development Division, OAQPS, EPA. Memo to E. J. Lillis, Control Programs Development Division, OAQPS, EPA, Emission Source Data for In-Stack Monitoring Regulations, June 4, 1975.

1. Section 51.1 is amended by adding paragraphs (z), (aa), (bb), (cc), (dd), and (ee) as follows:

#### § 51.1 Definitions.

(z) "Emission standard" means a regulation (or portion thereof) setting forth an allowable rate of emissions, level of opacity, or prescribing equipment or fuel specifications that result in control of air pollution emissions.

(aa) "Capacity factor" means the ratio of the average load on a machine or equipment for the period of time considered to the capacity rating of the machine or equipment.

(bb) "Excess emissions" means emissions of an air pollutant in excess of an emission standard.

(cc) "Nitric acid plant" means any facility producing nitric acid 30 to 70 percent in strength by either the pressure or atmospheric pressure process.

(dd) "Sulfuric acid plant" means any facility producing sulfuric acid by the contact process by burning elemental sulfur, alkylation acid, hydrogen sulfide, 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.

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

2. Section 51.19 is amended by adding paragraph (e) as follows:

#### § 51.19 Source surveillance.

(e) Legally enforceable procedures to require stationary sources subject to emission standards as part of an applicable plan to install, calibrate, maintain, and operate equipment for continuously monitoring and recording emissions; and to provide other information as specified in Appendix P of this part.

(1) Such procedures shall identify the types of sources, by source category and capacity, that must install such instruments, and shall identify for each source category the pollutants which must be monitored.

(2) Such procedures shall, as a minimum, require the types of sources set forth in Appendix P of this part (as such appendix may be amended from time to time) to meet the applicable requirements set forth therein.

(3) Such procedures shall contain provisions which require the owner or operator of each source subject to continuous emission monitoring and recording requirements to maintain a file of all pertinent information. Such information shall include emission measurements, continuous monitoring system performance testing measurements, performance evaluations, calibration checks, and adjustments and maintenance performed on such monitoring systems and other reports and records required by Appendix P of this Part for at least two years following the date of such measurements or maintenance.

(4) Such procedures shall require the source owner or operator to submit information relating to emissions and operation of the emission monitors to the State to the extent described in Appendix P as frequently or more frequently as described therein.

(5) Such procedures shall provide that sources subject to the requirements of § 51.19(e)(2) of this section shall have installed all necessary equipment and shall have begun monitoring and recording within 18 months of (1) the approval of a State plan requiring monitoring for that source or (2) promulgation by the Agency of monitoring requirements for that source. However, sources that have made good faith efforts to purchase, install, and begin the monitoring and recording of emission data but who have been unable to complete such installation within the time period provided may be given reasonable extensions of time as deemed appropriate by the State.

(6) States shall submit revisions to the applicable plan which implement the provisions of this section by October 6, 1976.

3. In Part 51, Appendix P is added as follows:

#### APPENDIX P—MINIMUM EMISSION MONITORING REQUIREMENTS

1.0 Purpose. This Appendix P sets forth the minimum requirements for continuous emission monitoring and recording that each State Implementation Plan must include in order to be approved under the provisions of 40 CFR 51.19(e). These requirements include the source categories to be affected; emission monitoring, recording, and reporting requirements for these sources; performance specifications for accuracy, reliability, and durability of acceptable monitoring systems; and techniques to convert emission data to units of the applicable State emission standard. Such data must be reported to the State as an indication of whether proper maintenance and operating procedures are being utilized by source operators to maintain emission levels at or below emission standards. Such data may be used directly or in-

directly for compliance determination or any other purpose deemed appropriate by the State. Though the monitoring requirements are specified in detail, States are given some flexibility to resolve difficulties that may arise during the implementation of these regulations.

##### 1.1 Applicability.

The State plan shall require the owner or operator of an emission source in a category listed in this Appendix to: (1) install, calibrate, operate, and maintain all monitoring equipment necessary for continuously monitoring the pollutants specified in this Appendix for the applicable source category; and (2) complete the installation and performance tests of such equipment and begin monitoring and recording within 18 months of plan approval or promulgation. The source categories and the respective monitoring requirements are listed below.

1.1.1 Fossil fuel-fired steam generators, as specified in paragraph 2.1 of this appendix, shall be monitored for opacity, nitrogen oxides emissions, sulfur dioxide emissions, and oxygen or carbon dioxide.

1.1.2 Fluid bed catalytic cracking unit catalyst regenerators, as specified in paragraph 2.4 of this appendix, shall be monitored for opacity.

1.1.3 Sulfuric acid plants, as specified in paragraph 2.3 of this appendix, shall be monitored for sulfur dioxide emissions.

1.1.4 Nitric acid plants, as specified in paragraph 2.2 of this appendix, shall be monitored for nitrogen oxides emissions.

##### 1.2 Exemptions.

The States may include provisions within their regulations to grant exemptions from the monitoring requirements of paragraph 1.1 of this appendix for any source which is:

1.2.1 subject to a new source performance standard promulgated in 40 CFR Part 60 pursuant to Section 111 of the Clean Air Act; or

1.2.2 not subject to an applicable emission standard of an approved plan; or

1.2.3 scheduled for retirement within 5 years after inclusion of monitoring requirements for the source in Appendix P, provided that adequate evidence and guarantees are provided that clearly show that the source will cease operations prior to such date.

##### 1.3 Extensions.

States may allow reasonable extensions of the time provided for installation of monitors for facilities unable to meet the prescribed timeframe (i.e., 18 months from plan approval or promulgation) provided the owner or operator of such facility demonstrates that good faith efforts have been made to obtain and install such devices within such prescribed timeframe.

##### 1.4 Monitoring System Malfunction.

The State plan may provide a temporary exemption from the monitoring and reporting requirements of this appendix during any period of monitoring system malfunction, provided that the source owner or operator shows, to the satisfaction of the State, that the malfunction was unavoidable and is being repaired as expeditiously as practicable.

##### 2.0 Minimum Monitoring Requirement.

States must, as a minimum, require the sources listed in paragraph 1.1 of this appendix to meet the following basic requirements.

##### 2.1 Fossil fuel-fired steam generators.

Each fossil fuel-fired steam generator, except as provided in the following subparagraphs, with an annual average capacity factor of greater than 30 percent, as reported to the Federal Power Commission for calendar year 1974, or as otherwise demonstrated to the State by the owner or operator, shall conform with the following monitoring requirements when such facility is subject to an emission standard of an applicable plan for the pollutant in question.

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2.1.1 A continuous monitoring system for the measurement of opacity which meets the performance specifications of paragraph 3.1.1 of this appendix shall be installed, calibrated, maintained, and operated in accordance with the procedures of this appendix by the owner or operator of any such steam generator of greater than 250 million BTU per hour heat input except where:

2.1.1.1 Gaseous fuel is the only fuel burned, or

2.1.1.2 oil or a mixture of gas and oil are the only fuels burned and the source is able to comply with the applicable particulate matter and opacity regulations without utilization of particulate matter collection equipment, and where the source has never been found, through any administrative or judicial proceedings, to be in violation of any visible emission standard of the applicable plan.

2.1.2 A continuous monitoring system for the measurement of sulfur dioxide which meets the performance specifications of paragraph 3.1.3 of this appendix shall be installed, calibrated, maintained, and operated on any fossil fuel-fired steam generator of greater than 250 million BTU per hour heat input which has installed sulfur dioxide pollutant control equipment.

2.1.3 A continuous monitoring system for the measurement of nitrogen oxides which meets the performance specification of paragraph 3.1.2 of this appendix shall be installed, calibrated, maintained, and operated on fossil fuel-fired steam generators of greater than 1000 million BTU per hour heat input when such facility is located in an Air Quality Control Region where the Administrator has specifically determined that a control strategy for nitrogen dioxide is necessary to attain the national standards, unless the source owner or operator demonstrates during source compliance tests as required by the State that such a source emits nitrogen oxides at levels 30 percent or more below the emission standard within the applicable plan.

2.1.4 A continuous monitoring system for the measurement of the percent oxygen or carbon dioxide which meets the performance specifications of paragraphs 3.1.4 or 3.1.5 of this appendix shall be installed, calibrated, operated, and maintained on fossil fuel-fired steam generators where measurements of oxygen or carbon dioxide in the flue gas are required to convert either sulfur dioxide or nitrogen oxides continuous emission monitoring data, or both, to units of the emission standard within the applicable plan.

### 2.2 Nitric acid plants.

Each nitric acid plant of greater than 300 tons per day production capacity, the production capacity being expressed as 100 percent acid, located in an Air Quality Control Region where the Administrator has specifically determined that a control strategy for nitrogen dioxide is necessary to attain the national standard shall install, calibrate, maintain, and operate a continuous monitoring system for the measurement of nitrogen oxides which meets the performance specifications of paragraph 3.1.2 for each nitric acid producing facility within such plant.

### 2.3 Sulfuric acid plants.

Each sulfuric acid plant of greater than 300 tons per day production capacity, the production being expressed as 100 percent acid, shall install, calibrate, maintain and operate a continuous monitoring system for the measurement of sulfur dioxide which meets the performance specifications of 3.1.3 for each sulfuric acid producing facility within such plant.

2.4 Fluid bed catalytic cracking unit catalyst regenerators at petroleum refineries.

Each catalyst regenerator for fluid bed catalytic cracking units of greater than 20,000 barrels per day fresh feed capacity shall install, calibrate, maintain, and operate a continuous monitoring system for the measurement of opacity which meets the performance specifications of 3.1.1.

### 3.0 Minimum specifications.

All State plans shall require owners or operators of monitoring equipment installed to comply with this Appendix, except as provided in paragraph 3.2, to demonstrate compliance with the following performance specifications.

#### 3.1 Performance specifications.

The performance specifications set forth in Appendix B of Part 60 are incorporated herein by reference, and shall be used by States to determine acceptability of monitoring equipment installed pursuant to this Appendix except that (1) where reference is made to the "Administrator" in Appendix B, Part 60, the term "State" should be inserted for the purpose of this Appendix (e.g., in Performance Specification 1, 1.2, "... monitoring systems subject to approval by the Administrator," should be interpreted as "... monitoring systems subject to approval by the State"), and (2) where reference is made to the "Reference Method" in Appendix B, Part 60, the State may allow the use of either the State approved reference method or the Federally approved reference method as published in Part 60 of this Chapter. The Performance Specifications to be used with each type of monitoring system are listed below.

3.1.1 Continuous monitoring systems for measuring opacity shall comply with Performance Specification 1.

3.1.2 Continuous monitoring systems for measuring nitrogen oxides shall comply with Performance Specification 2.

3.1.3 Continuous monitoring systems for measuring sulfur dioxide shall comply with Performance Specification 2.

3.1.4 Continuous monitoring systems for measuring oxygen shall comply with Performance Specification 3.

3.1.5 Continuous monitoring systems for measuring carbon dioxide shall comply with Performance Specification 3.

#### 3.2 Exemptions.

Any source which has purchased an emission monitoring system(s) prior to September 11, 1974, may be exempt from meeting such test procedures prescribed in Appendix B of Part 60 for a period not to exceed five years from plan approval or promulgation.

#### 3.3 Calibration Gases.

For nitrogen oxides monitoring systems installed on fossil fuel-fired steam generators the pollutant gas used to prepare calibration gas mixtures (Section 2.1, Performance Specification 2, Appendix B, Part 60) shall be nitric oxide (NO). For nitrogen oxides monitoring systems installed on nitric acid plants the pollutant gas used to prepare calibration gas mixtures (Section 2.1, Performance Specification 2, Appendix B, Part 60 of this Chapter) shall be nitrogen dioxide (NO<sub>2</sub>). These gases shall also be used for daily checks under paragraph 3.7 of this appendix as applicable. For sulfur dioxide monitoring systems installed on fossil fuel-fired steam generators or sulfuric acid plants the pollutant gas used to prepare calibration gas mixtures (Section 2.1, Performance Specification 2, Appendix B, Part 60 of this Chapter) shall be sulfur dioxide (SO<sub>2</sub>). Span and zero gases should be traceable to National Bureau of Standards reference gases whenever these reference gases are available. Every six months from date of manufacture, span and zero gases shall be reanalyzed by conducting triplicate analyses using the reference methods in Appendix A, Part 60 of this chapter as follows: for sulfur dioxide, use Reference Method 6; for nitrogen oxides, use Reference Method 7;

and for carbon dioxide or oxygen, use Reference Method 3. The gases may be analyzed at less frequent intervals if longer shelf lives are guaranteed by the manufacturer.

#### 3.4 Cycling times.

Cycling times include the total time a monitoring system requires to sample, analyze and record an emission measurement.

3.4.1 Continuous monitoring systems for measuring opacity shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 10-second period.

3.4.2 Continuous monitoring systems for measuring oxides of nitrogen, carbon dioxide, oxygen, or sulfur dioxide shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

#### 3.5 Monitor location.

State plans shall require all continuous monitoring systems or monitoring devices to be installed such that representative measurements of emissions or process parameters (i.e., oxygen, or carbon dioxide) from the affected facility are obtained. Additional guidance for location of continuous monitoring systems to obtain representative samples are contained in the applicable Performance Specifications of Appendix B of Part 60 of this Chapter.

#### 3.6 Combined effluents.

When the effluents from two or more affected facilities of similar design and operating characteristics are combined before being released to the atmosphere, the State plan may allow monitoring systems to be installed on the combined effluent. When the affected facilities are not of similar design and operating characteristics, or when the effluent from one affected facility is released to the atmosphere through more than one point, the State should establish alternate procedures to implement the intent of these requirements.

#### 3.7 Zero and drift.

State plans shall require owners or operators of all continuous monitoring systems installed in accordance with the requirements of this Appendix to record the zero and span drift in accordance with the method prescribed by the manufacturer of such instruments; to subject the instruments to the manufacturer's recommended zero and span check at least once daily unless the manufacturer has recommended adjustments at shorter intervals, in which case such recommendations shall be followed; to adjust the zero and span whenever the 24-hour zero drift or 24-hour calibration drift limits of the applicable performance specifications in Appendix B of Part 60 are exceeded; and to adjust continuous monitoring systems referenced by paragraph 3.2 of this Appendix whenever the 24-hour zero drift or 24-hour calibration drift exceed 10 percent of the emission standard.

#### 3.8 Span.

Instrument span should be approximately 200 percent of the expected instrument data display output corresponding to the emission standard for the source.

#### 3.9 Alternative procedures and requirements.

In cases where States wish to utilize different, but equivalent, procedures and requirements for continuous monitoring systems, the State plan must provide a description of such alternative procedures for approval by the Administrator. Some examples of situations that may require alternatives follow:

3.9.1 Alternative monitoring requirements to accommodate continuous monitoring systems that require corrections for stack moisture conditions (e.g., an instrument measuring steam generator SO<sub>2</sub> emissions on a wet basis could be used with an instrument measuring oxygen concentration on a dry basis if acceptable methods of measuring stack moisture conditions are used to allow ac-

## RULES AND REGULATIONS

curate adjustment of the measured SO<sub>2</sub> concentration to dry basis.)

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

3.9.3 Alternative procedures for performing calibration checks (e.g., some instruments may demonstrate superior drift characteristics that require checking at less frequent intervals).

3.9.4 Alternative monitoring requirements when the effluent from one affected facility or the combined effluent from two or more identical affected facilities is released to the atmosphere through more than one point (e.g., an extractive, gaseous monitoring system used at several points may be approved if the procedures recommended are suitable for generating accurate emission averages).

3.9.5 Alternative continuous monitoring systems that do not meet the spectral response requirements in Performance Specification 1, Appendix B of Part 60, but adequately demonstrate a definite and consistent relationship between their measurements and the opacity measurements of a system complying with the requirements in Performance Specification 1. The State may require that such demonstration be performed for each affected facility.

### 4.0 Minimum data requirements.

The following paragraphs set forth the minimum data reporting requirements necessary to comply with § 51.19(e) (3) and (4).

4.1 The State plan shall require owners or operators of facilities required to install continuous monitoring systems to submit a written report of excess emissions for each calendar quarter and the nature and cause of the excess emissions, if known. The averaging period used for data reporting should be established by the State to correspond to the averaging period specified in the emission test method used to determine compliance with an emission standard for the pollutant source category in question. The required report shall include, as a minimum, the data stipulated in this Appendix.

4.2 For opacity measurements, the summary shall consist of the magnitude in actual percent opacity of all one-minute (or such other time period deemed appropriate by the State) averages of opacity greater than the opacity standard in the applicable plan for each hour of operation of the facility. Average values may be obtained by integration over the averaging period or by arithmetically averaging a minimum of four equally spaced, instantaneous opacity measurements per minute. Any time period exempted shall be considered before determining the excess averages of opacity (e.g., whenever a regulation allows two minutes of opacity measurements in excess of the standard, the State shall require the source to report all opacity averages. In any one hour, in excess of the standard, minus the two-minute exemption). If more than one opacity standard applies, excess emissions data must be submitted in relation to all such standards.

4.3 For gaseous measurements the summary shall consist of emission averages, in the units of the applicable standard, for each averaging period during which the applicable standard was exceeded.

4.4 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 system repairs or adjustments shall be reported. The State may require proof of continuous monitoring system performance whenever system repairs or adjustments have been made.

4.5 When no excess emissions have occurred and the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be included in the report.

4.6 The State plan shall require owners or operators of affected facilities to maintain a file of all information reported in the quarterly summaries, and all other data collected either by the continuous monitoring system or as necessary to convert monitoring data to the units of the applicable standard for a minimum of two years from the date of collection of such data or submission of such summaries.

### 5.0 Data Reduction

The State plan shall require owners or operators of affected facilities to use the following procedures for converting monitoring data to units of the standard where necessary.

5.1 For fossil fuel-fired steam generators the following procedures shall be used to convert gaseous emission monitoring data in parts per million to g/million cal (lb/million BTU) where necessary:

5.1.1 When the owner or operator of a fossil fuel-fired steam generator elects under subparagraph 2.1.4 of this Appendix to measure oxygen in the flue gases, the measurements of the pollutant concentration and oxygen concentration shall each be on a dry basis and the following conversion procedure used:

$$E = CF \left( \frac{20.9}{20.9 - \%O_2} \right)$$

5.1.2 When the owner or operator elects under subparagraph 2.1.4 of this Appendix to measure carbon dioxide in the flue gases, the measurement of the pollutant concentration and the carbon dioxide concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure used:

$$E = CF \left( \frac{100}{\%CO_2} \right)$$

5.1.3 The values used in the equations under paragraph 5.1 are derived as follows:

E = pollutant emission, g/million cal (lb/million BTU).

C = pollutant concentration, g/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each hourly period by  $4.16 \times 10^{-5}$  M g/dscm per ppm ( $2.64 \times 10^{-6}$  M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64 for sulfur dioxide and 46 for oxides of nitrogen.

%O<sub>2</sub>, %CO<sub>2</sub> = Oxygen or carbon dioxide volume (expressed as percent) determined with equipment specified under paragraph 4.1.4 of this appendix.

F, F<sub>2</sub> = 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<sub>2</sub>) respectively. Values of F and F<sub>2</sub> are given in § 60.45(f) of Part 60, as applicable.

5.2 For sulfuric acid plants the owner or operator shall:

5.2.1 establish a conversion factor three times daily according to the procedures to § 60.84(b) of this chapter;

5.2.2 multiply the conversion factor by the average sulfur dioxide concentration in the

flue gases to obtain average sulfur dioxide emissions in Kg/metric ton (lb/short ton); and

5.2.3 report the average sulfur dioxide emission for each averaging period in excess of the applicable emission standard in the quarterly summary.

5.3 For nitric acid plants the owner or operator shall:

5.3.1 establish a conversion factor according to the procedures of § 60.73(b) of this chapter.

5.3.2 multiply the conversion factor by the average nitrogen oxides concentration in the flue gases to obtain the nitrogen oxides emissions in the units of the applicable standard;

5.3.3 report the average nitrogen oxides emission for each averaging period in excess of the applicable emission standard, in the quarterly summary.

5.4 Any State may allow data reporting or reduction procedures varying from those set forth in this Appendix if the owner or operator of a source shows to the satisfaction of the State that his procedures are at least as accurate as those in this Appendix. Such procedures may include but are not limited to the following:

5.4.1 Alternative procedures for computing emission averages that do not require integration of data (e.g., some facilities may demonstrate that the variability of their emissions is sufficiently small to allow accurate reduction of data based upon computing averages from equally spaced data points over the averaging period).

5.4.2 Alternative methods of converting pollutant concentration measurements to the units of the emission standards.

### 6.0 Special Consideration.

The State plan may provide for approval, on a case-by-case basis, of alternative monitoring requirements different from the provisions of Parts 1 through 5 of this Appendix if the provisions of this Appendix (i.e., the installation of a continuous emission monitoring system) cannot be implemented by a source due to physical plant limitations or extreme economic reasons. To make use of this provision, States must include in their plan specific criteria for determining those physical limitations or extreme economic situations to be considered by the State. In such cases, when the State exempts any source subject to this Appendix by use of this provision from installing continuous emission monitoring systems, the State shall set forth alternative emission monitoring and reporting requirements (e.g., periodic manual stack tests) to satisfy the intent of these regulations. Examples of such special cases include, but are not limited to, the following:

6.1 Alternative monitoring requirements may be prescribed when installation of a continuous monitoring system or monitoring device specified by this Appendix would not provide accurate determinations of emissions (e.g., condensed, uncombined water vapor may prevent an accurate determination of opacity using commercially available continuous monitoring systems).

6.2 Alternative monitoring requirements may be prescribed when the affected facility is infrequently operated (e.g., some affected facilities may operate less than one month per year).

6.3 Alternative monitoring requirements may be prescribed when the State determines that the requirements of this Appendix would impose an extreme economic burden on the source owner or operator.

6.4 Alternative monitoring requirements may be prescribed when the State determines that monitoring systems prescribed by this Appendix cannot be installed due to physical limitations at the facility.

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**ENVIRONMENTAL  
PROTECTION  
AGENCY**

**NATIONAL EMISSION  
STANDARDS FOR  
HAZARDOUS AIR  
POLLUTANTS**

**Subpart F—National Emission Standard  
for Vinyl Chloride**

**§ 61.60 Applicability.**

(a) This subpart applies to plants which produce:

(1) Ethylene dichloride by reaction of oxygen and hydrogen chloride with ethylene,

(2) Vinyl chloride by any process, and/or

(3) One or more polymers containing any fraction of polymerized vinyl chloride.

(b) This subpart does not apply to equipment used in research and development if the reactor used to polymerize the vinyl chloride processed in the equipment has a capacity of no more than 0.19 m<sup>3</sup> (50 gal).

(c) Sections of this subpart other than §§ 61.61; 61.64 (a) (1), (b), (c), and (d); 61.67; 61.68; 61.69; 61.70; and 61.71 do not apply to equipment used in research and development if the reactor used to polymerize the vinyl chloride processed in the equipment has a capacity of greater than 0.19 m<sup>3</sup> (50 gal) and no more than 4.07 m<sup>3</sup> (1100 gal).

**§ 61.61 Definitions.**

Terms used in this subpart are defined in the Act, in subpart A of this part, or in this section as follows:

(a) "Ethylene dichloride plant" includes any plant which produces ethylene dichloride by reaction of oxygen and hydrogen chloride with ethylene.

(b) "Vinyl chloride plant" includes any plant which produces vinyl chloride by any process.

(c) "Polyvinyl chloride plant" includes any plant where vinyl chloride alone or in combination with other materials is polymerized.

(d) "Slip gauge" means a gauge which has a probe that moves through the gas/liquid interface in a storage or transfer vessel and indicates the level of vinyl chloride in the vessel by the physical state of the material the gauge discharges.

(e) "Type of resin" means the broad classification of resin referring to the basic manufacturing process for producing that resin, including, but not limited to, the suspension, dispersion, latex, bulk, and solution processes.

(f) "Grade of resin" means the subdivision of resin classification which describes it as a unique resin, i.e., the most exact description of a resin with no further subdivision.

(g) "Dispersion resin" means a resin manufactured in such away as to form fluid dispersions when dispersed in a plasticizer or plasticizer/diluent mixtures.

(h) "Latex resin" means a resin which is produced by a polymerization process which initiates from free radical catalyst sites and is sold undried.

(i) "Bulk resin" means a resin which is produced by a polymerization process in which no water is used.

(j) "Inprocess wastewater" means any water which, during manufacturing or

processing, comes into direct contact with vinyl chloride or polyvinyl chloride or results from the production or use of any raw material, intermediate product, finished product, by-product, or waste product containing vinyl chloride or polyvinyl chloride but which has not been discharged to a wastewater treatment process or discharged untreated as wastewater.

(k) "Wastewater treatment process" includes any process which modifies characteristics such as BOD, COD, TSS, and pH, usually for the purpose of meeting effluent guidelines and standards; it does not include any process the purpose of which is to remove vinyl chloride from water to meet requirements of this subpart.

(l) "In vinyl chloride service" means that a piece of equipment contains or contacts either a liquid that is at least 10 percent by weight vinyl chloride or a gas that is at least 10 percent by volume vinyl chloride.

(m) "Standard operating procedure" means a formal written procedure officially adopted by the plant owner or operator and available on a routine basis to those persons responsible for carrying out the procedure.

(n) "Run" means the net period of time during which an emission sample is collected.

(o) "Ethylene dichloride purification" includes any part of the process of ethylene dichloride production which follows ethylene dichloride formation and in which finished ethylene dichloride is produced.

(p) "Vinyl chloride purification" includes any part of the process of vinyl chloride production which follows vinyl chloride formation and in which finished vinyl chloride is produced.

(q) "Reactor" includes any vessel in which vinyl chloride is partially or totally polymerized into polyvinyl chloride.

(r) "Reactor opening loss" means the emissions of vinyl chloride occurring when a reactor is vented to the atmosphere for any purpose other than an emergency relief discharge as defined in § 61.65(a).

(s) "Stripper" includes any vessel in which residual vinyl chloride is removed from polyvinyl chloride resin, except bulk resin, in the slurry form by the use of heat and/or vacuum. In the case of bulk resin, stripper includes any vessel which is used to remove residual vinyl chloride from polyvinyl chloride resin immediately following the polymerization step in the plant process flow.

(t) "Standard temperature" means a temperature of 20° C (69° F).

(u) "Standard pressure" means a pressure of 760 mm of Hg (29.92 in. of Hg).

**§ 61.62 Emission standard for ethylene dichloride plants.**

(a) Ethylene dichloride purification: The concentration of vinyl chloride in all exhaust gases discharged to the atmosphere from any equipment used in ethylene dichloride purification is not to exceed 10 ppm, except as provided in

§ 61.65(a). This requirement does not apply to equipment that has been opened, is out of operation, and met the requirement in § 61.65(b) (6) (i) before being opened.

(b) Oxychlorination reactor: Except as provided in § 61.65(a), emissions of vinyl chloride to the atmosphere from each oxychlorination reactor are not to exceed 0.2 g/kg (0.0002 lb/lb) of the 100 percent ethylene dichloride product from the oxychlorination process.

**§ 61.63 Emission standard for vinyl chloride plants.**

An owner or operator of a vinyl chloride plant shall comply with the requirements of this section and § 61.65.

(a) Vinyl chloride formation and purification: The concentration of vinyl chloride in all exhaust gases discharged to the atmosphere from any equipment used in vinyl chloride formation and/or purification is not to exceed 10 ppm, except as provided in § 61.65(a). This requirement does not apply to equipment that has been opened, is out of operation, and met the requirement in § 61.65(b) (6) (i) before being opened.

**§ 61.64 Emission standard for polyvinyl chloride plants.**

An owner or operator of a polyvinyl chloride plant shall comply with the requirements of this section and § 61.65.

(a) Reactor: The following requirements apply to reactors:

(1) The concentration of vinyl chloride in all exhaust gases discharged to the atmosphere from each reactor is not to exceed 10 ppm, except as provided in paragraph (a) (2) of this section and § 61.65(a).

(2) The reactor opening loss from each reactor is not to exceed 0.02 g vinyl chloride/Kg (0.00002 lb vinyl chloride/lb) of polyvinyl chloride product, with the product determined on a dry solids basis. This requirement applies to any vessel which is used as a reactor or as both a reactor and a stripper. In the bulk process, the product means the gross product of prepolymerization and postpolymerization.

(3) Manual vent valve discharge: Except for an emergency manual vent valve discharge, there is to be no discharge to the atmosphere from any manual vent valve on a polyvinyl chloride reactor in vinyl chloride service. An emergency manual vent valve discharge means a discharge to the atmosphere which could not have been avoided by taking measures to prevent the discharge. Within 10 days of any discharge to the atmosphere from any manual vent valve, the owner or operator of the source from which the discharge occurs shall submit to the Administrator a report in writing containing information on the source, nature and cause of the discharge, the date and time of the discharge, the approximate total vinyl chloride loss during the discharge, the method used for determining the vinyl chloride loss, the action that was taken to prevent the discharge, and measures adopted to prevent future discharges.

(b) **Stripper:** The concentration of vinyl chloride in all exhaust gases discharged to the atmosphere from each stripper is not to exceed 10 ppm, except as provided in § 61.65(a). This requirement does not apply to equipment that has been opened, is out of operation, and met the requirement in § 61.65(b) (6) (i) before being opened.

(c) **Mixing, weighing, and holding containers:** The concentration of vinyl chloride in all exhaust gases discharged to the atmosphere from each mixing, weighing, or holding container in vinyl chloride service which precedes the stripper (or the reactor if the plant has no stripper) in the plant process flow is not to exceed 10 ppm, except as provided in § 61.65(a). This requirement does not apply to equipment that has been opened, is out of operation, and met the requirement in § 61.65(b) (6) (i) before being opened.

(d) **Monomer recovery system.** The concentration of vinyl chloride in all exhaust gases discharged to the atmosphere from each monomer recovery system is not to exceed 10 ppm, except as provided in § 61.65(a). This requirement does not apply to equipment that has been opened, is out of operation, and met the requirement in § 61.65(b) (6) (i) before being opened.

(e) **Sources following the stripper(s):** The following requirements apply to emissions of vinyl chloride to the atmosphere from the combination of all sources following the stripper(s) [or the reactor(s) if the plant has no stripper(s)] in the plant process flow including but not limited to, centrifuges, concentrators, blend tanks, filters, dryers, conveyor air discharges, baggers, storage containers, and inprocess wastewater:

(1) In polyvinyl chloride plants using stripping technology to control vinyl chloride emissions, the weighted average residual vinyl chloride concentration in all grades of polyvinyl chloride resin processed through the stripping operation on each calendar day, measured immediately after the stripping operation is completed, may not exceed:

(i) 2000 ppm for polyvinyl chloride dispersion resins, excluding latex resins;

(ii) 400 ppm for all other polyvinyl chloride resins, including latex resins, averaged separately for each type of resin; or

(2) In polyvinyl chloride plants controlling vinyl chloride emissions with technology other than stripping or in addition to stripping, emissions of vinyl chloride to the atmosphere may not exceed:

(i) 2 g/kg (0.002 lb/lb) product from the stripper(s) [or reactor(s) if the plant has no stripper(s)] for dispersion polyvinyl chloride resins, excluding latex resins, with the product determined on a dry solids basis;

(ii) 0.4 g/kg (0.0004 lb/lb) product from the strippers [or reactor(s) if the plant has no stripper(s)] for all other polyvinyl chloride resins, including latex resins, with the product determined on a dry solids basis.

#### § 61.65 Emission standard for ethylene dichloride, vinyl chloride and polyvinyl chloride plants.

An owner or operator of an ethylene dichloride, vinyl chloride, and/or polyvinyl chloride plant shall comply with the requirements of this section.

(a) **Relief valve discharge:** Except for an emergency relief discharge, there is to be no discharge to the atmosphere from any relief valve on any equipment in vinyl chloride service. An emergency relief discharge means a discharge which could not have been avoided by taking measures to prevent the discharge. Within 10 days of any relief valve discharge, the owner or operator of the source from which the relief valve discharge occurs shall submit to the Administrator a report in writing containing information on the source, nature and cause of the discharge, the date and time of the discharge, the approximate total vinyl chloride loss during the discharge, the method used for determining the vinyl chloride loss, the action that was taken to prevent the discharge, and measures adopted to prevent future discharges.

(b) **Fugitive emission sources:**

(i) **Loading and unloading lines:** Vinyl chloride emissions from loading and unloading lines in vinyl chloride service which are opened to the atmosphere after each loading or unloading operation are to be minimized as follows:

(1) After each loading or unloading operation and before opening a loading or unloading line to the atmosphere, the quantity of vinyl chloride in all parts of each loading or unloading line that are to be opened to the atmosphere is to be reduced so that the parts combined contain no greater than 0.0038 m<sup>3</sup> (0.13 ft<sup>3</sup>) of vinyl chloride, at standard temperature and pressure; and

(ii) Any vinyl chloride removed from a loading or unloading line in accordance with paragraph (b) (1) (i) of this section is to be ducted through a control system from which the concentration of vinyl chloride in the exhaust gases does not exceed 10 ppm, or equivalent as provided in § 61.66.

(2) **Slip gauges:** During loading or unloading operations, the vinyl chloride emissions from each slip gauge in vinyl chloride service are to be minimized by ducting any vinyl chloride discharged from the slip gauge through a control system from which the concentration of vinyl chloride in the exhaust gases does not exceed 10 ppm, or equivalent as provided in § 61.66.

(3) **Leakage from pump, compressor, and agitator seals:**

(i) **Rotating pumps:** Vinyl chloride emissions from seals on all rotating pumps in vinyl chloride service are to be minimized by installing sealless pumps, pumps with double mechanical seals, or equivalent as provided in § 61.66. If double mechanical seals are used, vinyl chloride emission from the seals are to be minimized by maintaining the pressure between the two seals so that any leak that occurs is into the pump; by ducting any vinyl chloride between the two seals through a control system from

which the concentration of vinyl chloride in the exhaust gases does not exceed 10 ppm; or equivalent as provided in § 61.66.

(ii) **Reciprocating pumps:** Vinyl chloride emissions from seals on all reciprocating pumps in vinyl chloride service are to be minimized by installing double outboard seals, or equivalent as provided in § 61.66. If double outboard seals are used, vinyl chloride emissions from the seals are to be minimized by maintaining the pressure between the two seals so that any leak that occurs is into the pump; by ducting any vinyl chloride between the two seals through a control system from which the concentration of vinyl chloride in the exhaust gases does not exceed 10 ppm; or equivalent as provided in § 61.66.

(iii) **Rotating compressor:** Vinyl chloride emissions from seals on all rotating compressors in vinyl chloride service are to be minimized by installing compressors with double mechanical seals, or equivalent as provided in § 61.66. If double mechanical seals are used, vinyl chloride emissions from the seals are to be minimized by maintaining the pressure between the two seals so that any leak that occurs is into the compressor; by ducting any vinyl chloride between the two seals through a control system from which the concentration of vinyl chloride in the exhaust gases does not exceed 10 ppm; or equivalent as provided in § 61.66.

(iv) **Reciprocating compressors:** Vinyl chloride emissions from seals on all reciprocating compressors in vinyl chloride service are to be minimized by installing double outboard seals, or equivalent as provided in § 61.66. If double outboard seals are used, vinyl chloride emissions from the seals are to be minimized by maintaining the pressure between the two seals so that any leak that occurs is into the compressor; by ducting any vinyl chloride between the two seals through a control system from which the concentration of vinyl chloride in the exhaust gases does not exceed 10 ppm; or equivalent as provided in § 61.66.

(v) **Agitator:** Vinyl chloride emissions from seals on all agitators in vinyl chloride service are to be minimized by installing agitators with double mechanical seals, or equivalent as provided in § 61.66. If double mechanical seals are used, vinyl chloride emissions from the seals are to be minimized by maintaining the pressure between the two seals so that any leak that occurs is into the agitated vessel; by ducting any vinyl chloride between the two seals through a control system from which the concentration of vinyl chloride in the exhaust gases does not exceed 10 ppm; or equivalent as provided in § 61.66.

(4) **Leakage from relief valves:** Vinyl chloride emissions due to leakage from each relief valve on equipment in vinyl chloride service are to be minimized by installing a rupture disk between the equipment and the relief valve, by connecting the relief valve discharge to a process line or recovery system, or equivalent as provided in § 61.66.

(5) Manual venting of gases: Except as provided in § 61.64(a)(3), all gases which are manually vented from equipment in vinyl chloride service are to be ducted through a control system from which the concentration of vinyl chloride in the exhaust gases does not exceed 10 ppm; or equivalent as provided in § 61.66.

(6) Opening of equipment: Vinyl chloride emissions from opening of equipment (including loading or unloading lines that are not opened to the atmosphere after each loading or unloading operation) are to be minimized as follows:

(i) Before opening any equipment for any reason, the quantity of vinyl chloride is to be reduced so that the equipment contains no more than 2.0 percent by volume vinyl chloride or 0.0950 m<sup>3</sup> (25 gal) of vinyl chloride, whichever is larger, at standard temperature and pressure; and

(ii) Any vinyl chloride removed from the equipment in accordance with paragraph (b)(6)(i) of this section is to be ducted through a control system from which the concentration of vinyl chloride in the exhaust gases does not exceed 10 ppm, or equivalent as provided in § 61.66.

(7) Samples: Unused portions of samples containing at least 10 percent by weight vinyl chloride are to be returned to the process, and sampling techniques are to be such that sample containers in vinyl chloride service are purged into a closed process system.

(8) Leak detection and elimination: Vinyl chloride emissions due to leaks from equipment in vinyl chloride service are to be minimized by instituting and implementing a formal leak detection and elimination program. The owner or operator shall submit a description of the program to the Administrator for approval. The program is to be submitted within 45 days of the effective date of these regulations, unless a waiver of compliance is granted under § 61.11. If a waiver of compliance is granted, the program is to be submitted on a date scheduled by the Administrator. Approval of a program will be granted by the Administrator provided he finds:

(i) It includes a reliable and accurate vinyl chloride monitoring system for detection of major leaks and identification of the general area of the plant where a leak is located. A vinyl chloride monitoring system means a device which obtains air samples from one or more points on a continuous sequential basis and analyzes the samples with gas chromatography or, if the owner or operator assumes that all hydrocarbons measured are vinyl chloride, with infrared spectrophotometry flame ion detection, or an equivalent or alternative method.

(ii) It includes a reliable and accurate portable hydrocarbon detector to be used routinely to find small leaks and to pinpoint the major leaks indicated by the vinyl chloride monitoring system. A portable hydrocarbon detector means a device which measures hydrocarbons with a sensitivity of at least 10 ppm and is of such design and size that it can be used to measure emissions from localized points.

(iii) It provides for an acceptable calibration and maintenance schedule for the vinyl chloride monitoring system and portable hydrocarbon detector. For the vinyl chloride monitoring system, a daily span check is to be conducted with a concentration of vinyl chloride equal to the concentration defined as a leak according to paragraph (b)(8)(vi) of this section. The calibration is to be done with either:

(A) A calibration gas mixture prepared from the gases specified in sections 5.2.1 and 5.2.2 of Test Method 106 and in accordance with section 7.1 of Test Method 106, or

(B) A calibration gas cylinder standard containing the appropriate concentration of vinyl chloride. The gas composition of the calibration gas cylinder standard is to have been certified by the manufacturer. The manufacturer must have recommended a maximum shelf life for each cylinder so that the concentration does not change greater than  $\pm 5$  percent from the certified value. The date of gas cylinder preparation, certified vinyl chloride concentration and recommended maximum shelf life must have been affixed to the cylinder before shipment from the manufacturer to the buyer. If a gas chromatograph is used as the vinyl chloride monitoring system, these gas mixtures may be directly used to prepare a chromatograph calibration curve as described in section 7.3 of Test Method 106. The requirements in section 5.2.3.1 and 5.2.3.2 of Test Method 106 for certification of cylinder standards and for establishment and verification of calibration standards are to be followed.

(Secs. 112 and 301(a), Clean Air Act (42 U.S.C. 1857c-7 and 1857g(a)).)

(iv) The location and number of points to be monitored and the frequency of monitoring provided for in the program are acceptable when they are compared with the number of pieces of equipment in vinyl chloride service and the size and physical layout of the plant.

(v) It contains an acceptable plan of action to be taken when a leak is detected.

(vi) It contains a definition of leak which is acceptable when compared with the background concentrations of vinyl chloride in the areas of the plant to be monitored by the vinyl chloride monitoring system. Measurements of background concentrations of vinyl chloride in the areas of the plant to be monitored by the vinyl chloride monitoring system are to be included with the description of the program. The definition of leak for a given plant may vary among the different areas within the plant and is also to change over time as background concentrations in the plant are reduced.

(9) Inprocess wastewater: Vinyl chloride emissions to the atmosphere from inprocess wastewater are to be reduced as follows:

(i) The concentration of vinyl chloride in each inprocess wastewater stream

containing greater than 10 ppm vinyl chloride measured immediately as it leaves a piece of equipment and before being mixed with any other inprocess wastewater stream is to be reduced to no more than 10 ppm by weight before being mixed with any other inprocess wastewater stream which contains less than 10 ppm vinyl chloride; before being exposed to the atmosphere, before being discharged to a wastewater treatment process; or before being discharged untreated as a wastewater. This paragraph does apply to water which is used to displace vinyl chloride from equipment before it is opened to the atmosphere in accordance with § 61.64(a)(2) or paragraph (b)(6) of this section, but does not apply to water which is used to wash out equipment after the equipment has already been opened to the atmosphere in accordance with § 61.64(a)(2) or paragraph (b)(6) of this section.

(ii) Any vinyl chloride removed from the inprocess wastewater in accordance with paragraph (b)(9)(i) of this section is to be ducted through a control system from which the concentration of vinyl chloride in the exhaust gases does not exceed 10 ppm, or equivalent as provided in § 61.66.

(c) The requirements in paragraphs (b)(1), (b)(2), (b)(5), (b)(6), (b)(7) and (b)(8) of this section are to be incorporated into a standard operating procedure, and made available upon request for inspection by the Administrator. The standard operating procedure is to include provisions for measuring the vinyl chloride in equipment  $\geq 4.75$  m<sup>3</sup> (1.250 gal) in volume for which an emission limit is prescribed in § 61.65(b)(6).

(i) prior to opening the equipment and using Test Method 106, a portable hydrocarbon detector, or an equivalent or alternative method. The method of measurement is to meet the requirements in § 61.67(g)(5)(i)(A) or (g)(5)(i)(B).

#### § 61.66 Equivalent equipment and procedures.

Upon written application from an owner or operator, the Administrator may approve use of equipment or procedures which have been demonstrated to his satisfaction to be equivalent in terms of reducing vinyl chloride emissions to the atmosphere to those prescribed for compliance with a specific paragraph of this subpart. For an existing source, any request for using an equivalent method as the initial measure of control is to be submitted to the Administrator within 30 days of the effective date. For a new source, any request for using an equivalent method is to be submitted to the Administrator with the application for approval of construction or modification required by § 61.07.

#### § 61.67 Emission tests.

(a) Unless a waiver of emission testing is obtained under § 61.13, the owner or operator of a source to which this sub-

part applies shall test emissions from the source.

(1) Within 90 days of the effective date in the case of an existing source or a new source which has an initial startup date preceding the effective date, or

(2) Within 90 days of startup in the case of a new source, initial startup of which occurs after the effective date.

(b) The owner or operator shall provide the Administrator at least 30 days prior notice of an emission test to afford the Administrator the opportunity to have an observer present during the test.

(c) Any emission test is to be conducted while the equipment being tested is operating at the maximum production rate at which the equipment will be operated and under other relevant conditions as may be specified by the Administrator based on representative performance of the source.

(d) [Reserved]

(e) When at all possible, each sample is to be analyzed within 24 hours, but in no case in excess of 72 hours of sample collection. Vinyl chloride emissions are to be determined within 30 days after the emission test. The owner or operator shall report the determinations to the Administrator by a registered letter dispatched before the close of the next business day following the determination.

(f) The owner or operator shall retain at the plant and make available, upon request, for inspection by the Administrator, for a minimum of 2 years records of emission test results and other data needed to determine emissions.

(g) Unless otherwise specified, the owner or operator shall use test Test Methods in Appendix B to this part for each test as required by paragraphs (g)(1), (g)(2), (g)(3), (g)(4), and (g)(5) of this section, unless an equivalent method or an alternative method has been approved by the Administrator. If the Administrator finds reasonable grounds to dispute the results obtained by an equivalent or alternative method, he may require the use of a reference method. If the results of the reference and equivalent or alternative methods do not agree, the results obtained by the reference method prevail, and the Administrator may notify the owner or operator that approval of the method previously considered to be equivalent or alternative is withdrawn.

(1) Test Method 106 is to be used to determine the vinyl chloride emissions from any source for which an emission limit is prescribed in §§ 61.62(a) or (b) § 61.63(a), or §§ 61.64(a)(1), (b), (c), or (d), or from any control system to which reactor emissions are required to be ducted in § 61.64(a)(2) or to which fugitive emissions are required to be ducted in §§ 61.65(b)(1)(ii), (b)(2), (b)(5), (b)(6)(ii), or (b)(9)(ii).

(i) For each run, one sample is to be collected. The sampling site is to be at least two stack or duct diameters downstream and one half diameter upstream from any flow disturbance such as a bend, expansion, contraction, or visible flame. For a rectangular cross section an equivalent diameter is to be determined from the following equation:

$$\text{equivalent diameter} = 2 \frac{(\text{length})(\text{width})}{\text{length} + \text{width}}$$

The sampling point in the duct is to be at the centroid of the cross section. The sample is to be extracted at a rate proportional to the gas velocity at the sampling point. The sample is to be taken over a minimum of one hour, and is to contain a minimum volume of 50 liters corrected to standard conditions.

(ii) Each emission test is to consist of three runs. For the purpose of determining emissions, the average of results of all runs is to apply. The average is to be computed on a time weighted basis.

(iii) For gas streams containing more than 10 percent oxygen the concentration of vinyl chloride as determined by Test Method 106 is to be corrected to 10 percent oxygen (dry basis) for determination of emissions by using the following equation:

$$C_b (\text{corrected}) = C_b \frac{10.9}{20.9 - \text{percent } O_2}$$

where:

$C_b (\text{corrected})$  = The concentration of vinyl chloride in the exhaust gases, corrected to 10-percent oxygen.

$C_b$  = The concentration of vinyl chloride as measured by Test Method 106.

20.9 = Percent oxygen in the ambient air at standard conditions.

10.9 = Percent oxygen in the ambient air at standard conditions, minus the 10.0-percent oxygen to which the correction is being made.

Percent  $O_2$  = Percent oxygen in the exhaust gas as measured by Reference Method 3 in Appendix A of Part 60 of this chapter.

(iv) For those emission sources where the emission limit is prescribed in terms of mass rather than concentration, mass emissions in kg/100 kg product are to be determined by using the following equation:

$$C_{BX} = \frac{[C_b (2.60) Q 10^{-4}] [100]}{Z}$$

where:

$C_{BX}$  = kg vinyl chloride/100 kg product.

$C_b$  = The concentration of vinyl chloride as measured by Test Method 106.

2.60 = Density of vinyl chloride at one atmosphere and 20° C in kg/m<sup>3</sup>.

$Q$  = Volumetric flow rate in m<sup>3</sup>/hr as determined by Reference Method 2 of Appendix A to Part 60 of this chapter.

$10^{-4}$  = Conversion factor for ppm.

$Z$  = Production rate (kg/hr).

(2) Test Method 107 is to be used to determine the concentration of vinyl chloride in each inprocess wastewater stream for which an emission limit is prescribed in § 61.65(b)(9)(i).

(3) Where a stripping operation is used to attain the emission limit in § 61.64(e), emissions are to be determined using Test Method 107 as follows:

(i) The number of strippers and samples and the types and grades of resin to be sampled are to be determined by the Administrator for each individual plant at the time of the test based on the plant's operation.

(ii) Each sample is to be taken immediately following the stripping operation.

(iii) The corresponding quantity of material processed by each stripper is to be determined on a dry solids basis and by a method submitted to and approved by the Administrator.

(iv) At the prior request of the Administrator, the owner or operator shall provide duplicates of the samples required in paragraph (g)(3)(i) of this section.

(4) Where control technology other than or in addition to a stripping operation is used to attain the emission limit in § 61.64(e), emissions are to be determined as follows:

(i) Test Method 106 is to be used to determine atmospheric emissions from all of the process equipment simultaneously. The requirements of paragraph (g)(1) of this section are to be met.

(ii) Test Method 107 is to be used to determine the concentration of vinyl chloride in each inprocess wastewater stream subject to the emission limit prescribed in § 61.64(e). The mass of vinyl chloride in kg/100 kg product in each in process wastewater stream is to be determined by using the following equation:

$$C_{BX} = \frac{[C_d R 10^{-4}] [100]}{Z}$$

where:

$C_{BX}$  = kg vinyl chloride/100 kg product.

$C_d$  = the concentration of vinyl chloride as measured by Test Method 107.

$R$  = water flow rate in l/hr, determined in accordance with a method which has been submitted to and approved by the Administrator.

$10^{-4}$  = Conversion factor for ppm.

$Z$  = Production rate (kg/hr), determined in accordance with a method which has been submitted to and approved by the Administrator.

(5) The reactor opening loss for which an emission limit is prescribed in § 61.64(a)(2) is to be determined. The number of reactors for which the determination is to be made is to be specified by the Administrator for each individual plant at the time of the determination based on the plant's operation. For a reactor that is also used as a stripper, the determination may be made immediately following the stripping operation.

(i) Except as provided in paragraph (g)(5)(ii) of this section, the reactor opening loss is to be determined using the following equation:

$$C = \frac{W (2.60) (10^{-4}) (C_b)}{YZ}$$

where:

$C$  = kg vinyl chloride emissions/kg product.

$W$  = Capacity of the reactor in m<sup>3</sup>.

2.60 = Density of vinyl chloride at one atmosphere and 20° C in kg/m<sup>3</sup>.

$10^{-4}$  = Conversion factor for ppm.

$C_b$  = ppm by volume vinyl chloride as determined by Test Method 106 or a portable hydrocarbon detector which measures hydrocarbons with a sensitivity of at least 10 ppm.

$Y$  = Number of batches since the reactor was last opened to the atmosphere.

$Z$  = Average kg of polyvinyl chloride produced per batch in the number of batches since the reactor was last opened to the atmosphere.

(A) If Method 106 is used to determine the concentration of vinyl chloride ( $C_b$ ), the sample is to be withdrawn at a constant rate with a probe of sufficient length to reach the vessel bottom from the manhole. Samples are to be taken for 5 minutes within 6 inches of the ves-

sel bottom, 5 minutes near the vessel center, and 5 minutes near the vessel top.

(B) If a portable hydrocarbon detector is used to determine the concentration of vinyl chloride (Cb), a probe of sufficient length to reach the vessel bottom from the manhole is to be used to make the measurements. One measurement will be made within 6 inches of the vessel bottom, one near the vessel center and one near the vessel top. Measurements are to be made at each location until the reading is stabilized. All hydrocarbons measured are to be assumed to be vinyl chloride.

(C) The production rate of polyvinyl chloride (Z) is to be determined by a method submitted to and approved by the Administrator.

(ii) A calculation based on the number of evacuations, the vacuum involved, and the volume of gas in the reactor is hereby approved by the Administrator as an alternative method for determining reactor opening loss for postpolymerization reactors in the manufacture of bulk resins.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9).)

#### § 61.68 Emission monitoring.

(a) A vinyl chloride monitoring system is to be used to monitor on a continuous basis the emissions from the sources for which emission limits are prescribed in § 61.62(a) and (b), § 61.63(a), and § 61.64(a) (1), (b), (c), and (d), and for any control system to which reactor emissions are required to be ducted in § 61.64(a) (2) or to which fugitive emissions are required to be ducted in § 61.65(b) (1) (ii), and (b) (2), (b) (5), (b) (6) (ii), and (b) (9) (ii).

(b) The vinyl chloride monitoring system(s) used to meet the requirement in paragraph (a) of this section is to be a device which obtains air samples from one or more points on a continuous sequential basis and analyzes the samples with gas chromatography or, if the owner or operator assumes that all hydrocarbons measured are vinyl chloride, with infrared spectrophotometry, flame ion detection, or an equivalent or alternative method. The vinyl chloride monitoring system used to meet the requirements in § 61.65(b) (8) (i) may be used to meet the requirements of this section.

(c) A daily span check is to be conducted for each vinyl chloride monitoring system used. For all of the emission sources listed in paragraph (a) of this section, except the one for which an emission limit is prescribed in § 61.62(b), the daily span check is to be conducted with a concentration of vinyl chloride equal to 10 ppm. For the emission source for which an emission limit is prescribed in § 61.62(b), the daily span check is to be conducted with a concentration of vinyl chloride which is determined to be equivalent to the emis-

sion limit for that source based on the emission test required by § 61.67. The calibration is to be done with either:

(1) A calibration gas mixture prepared from the gases specified in sections 5.2.1 and 5.2.2 of Test Method 106 and in accordance with section 7.1 of Test Method 106, or

(2) A calibration gas cylinder standard containing the appropriate concentration of vinyl chloride. The gas composition of the calibration gas cylinder standard is to have been certified by the manufacturer. The manufacturer must have recommended a maximum shelf life for each cylinder so that the concentration does not change greater than  $\pm 5$  percent from the certified value. The date of gas cylinder preparation, certified vinyl chloride concentration and recommended maximum shelf life must have been affixed to the cylinder before shipment from the manufacturer to the buyer. If a gas chromatograph is used as the vinyl chloride monitoring system, these gas mixtures may be directly used to prepare a chromatograph calibration curve as described in section 7.3 of Test Method 106. The requirements in sections 5.2.3.1 and 5.2.3.2 of Test Method 106 for certification of cylinder standards and for establishment and verification of calibration standards are to be followed.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9).)

#### § 61.69 Initial report.

(a) An owner or operator of any source to which this subpart applies shall submit a statement in writing notifying the Administrator that the equipment and procedural specifications in §§ 61.65 (b) (1), (b) (2), (b) (3), (b) (4), (b) (5), (b) (6), (b) (7), and (b) (8) are being implemented.

(b) (1) In the case of an existing source or a new source which has an initial startup date preceding the effective date, the statement is to be submitted within 90 days of the effective date, unless a waiver of compliance is granted under § 61.11, along with the information required under § 61.10. If a waiver of compliance is granted, the statement is to be submitted on a date scheduled by the Administrator.

(2) In the case of a new source which did not have an initial startup date preceding the effective date, the statement is to be submitted within 90 days of the initial startup date.

(c) The statement is to contain the following information:

(1) A list of the equipment installed for compliance.

(2) A description of the physical and functional characteristics of each piece of equipment.

(3) A description of the methods which have been incorporated into the standard operating procedures for measuring or calculating the emissions for which emission limits are prescribed in §§ 61.65 (b) (1) (i) and (b) (6) (i).

(4) A statement that each piece of equipment is installed and that each

piece of equipment and each procedure is being used.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9).)

#### § 61.70 Semiannual report.

(a) The owner or operator of any (a) (2) is to be determined. The number source to which this subpart applies shall submit to the Administrator on September 15 and March 15 of each year a report in writing containing the information required by this section. The first semiannual report is to be submitted following the first full 6 month reporting period after the initial report is submitted.

(b) (1) In the case of an existing source or a new source which has an initial startup date preceding the effective date, the first report is to be submitted within 180 days of the effective date, unless a waiver of compliance is granted under § 61.11. If a waiver of compliance is granted, the first report is to be submitted on a date scheduled by the Administrator.

(2) In the case of a new source which did not have an initial startup date preceding the effective date, the first report is to be submitted within 180 days of the initial startup date.

(c) Unless otherwise specified, the owner or operator shall use the Test Methods in Appendix B to this part to conduct emission tests as required by paragraphs (c) (2) and (c) (3) of this section, unless an equivalent or an alternative method has been approved by the Administrator. If the Administrator finds reasonable grounds to dispute the results obtained by an equivalent or alternative method, he may require the use of a reference method. If the results of the reference and equivalent or alternative methods do not agree, the results obtained by the reference method prevail, and the Administrator may notify the owner or operator that approval of the method previously considered to be equivalent or alternative is withdrawn.

(1) The owner or operator shall include in the report a record of any emissions which averaged over any hour period (commencing on the hour) are in excess of the emission limits prescribed in §§ 61.62(a) or (b), § 61.63(a), or §§ 61.64(a) (1), (b), (c), or (d), or for any control system to which reactor emissions are required to be ducted in § 61.64(a) (2) or to which fugitive emissions are required to be ducted in § 61.65 (b) (1) (ii), (b) (2), (b) (5), (b) (6) (ii), or (b) (9) (ii). The emissions are to be measured in accordance with § 61.68.

(2) In polyvinyl chloride plants for which a stripping operation is used to attain the emission level prescribed in § 61.64(e), the owner or operator shall include in the report a record of the vinyl chloride content in the polyvinyl chloride resin. Test Method 107 is to be used to determine vinyl chloride content as follows:

(i) If batch stripping is used, one representative sample of polyvinyl chloride resin is to be taken from each batch of

each grade of resin immediately following the completion of the stripping operation, and identified by resin type and grade and the date and time the batch is completed. The corresponding quantity of material processed in each stripper batch is to be recorded and identified by resin type and grade and the date and time the batch is completed.

(ii) If continuous stripping is used, one representative sample of polyvinyl chloride resin is to be taken for each grade of resin processed or at intervals of 8 hours for each grade of resin which is being processed, whichever is more frequent. The sample is to be taken as the resin flows out of the stripper and identified by resin type and grade and the date and time the sample was taken. The corresponding quantity of material processed by each stripper over the time period represented by the sample during the eight hour period, is to be recorded

and identified by resin type and grade and the date and time it represents.

(iii) The quantity of material processed by the stripper is to be determined on a dry solids basis and by a method submitted to and approved by the Administrator.

(iv) At the prior request of the Administrator, the owner or operator shall provide duplicates of the samples required in paragraphs (c) (2) (i) and (c) (2) (ii) of this section.

(v) The report to the Administrator by the owner or operator is to include the vinyl chloride content found in each sample required by paragraphs (c) (2) (i) and (c) (2) (ii) of this section, averaged separately for each type of resin, over each calendar day and weighted according to the quantity of each grade of resin processed by the stripper(s) that calendar day, according to the following equation:

$$A_{T_i} = \frac{\sum_{i=1}^n P_{G_i} M_{G_i}}{Q_{T_i}} = \frac{P_{G_1} M_{G_1} + P_{G_2} M_{G_2} + \dots + P_{G_n} M_{G_n}}{Q_{T_i}}$$

where:

A = 24-hour average concentration of type  $T_i$  resin in ppm (dry weight basis).

Q = Total production of type  $T_i$  resin over the 24-hour period, in kg.

$T_i$  = Type of resin;  $i=1, 2, \dots, m$  where  $m$  is total number of resin types produced during the 24-hour period.

M = Concentration of vinyl chloride in one sample of grade  $G_i$  resin, in ppm.

P = Production of grade  $G_i$  resin represented by the sample, in kg.

$G_i$  = Grade of resin; e.g.,  $G_1, G_2$ , and  $G_3$ .

n = Total number of grades of resin produced during the 24-hour period.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9).)

#### § 61.71 Recordkeeping.

(a) The owner or operator of any source to which this subpart applies shall retain the following information at the source and make it available for inspection by the Administrator for a minimum of two years:

(1) A record of the leaks detected by the vinyl chloride monitoring system, as required by § 61.65(b) (8), including the concentrations of vinyl chloride as measured, analyzed, and recorded by the vinyl chloride detector, the location of each measurement and the date and approximate time of each measurement.

(2) A record of the leaks detected during routine monitoring with the portable hydrocarbon detector and the action taken to repair the leaks, as required by § 61.65(b) (8), including a brief statement explaining the location and cause of each leak detected with the portable hydrocarbon detector, the date and time of the leak, and any action taken to eliminate that leak.

(3) A record of emissions measured in accordance with § 61.68.

(4) A daily operating record for each polyvinyl chloride reactor, including pressures and temperatures.

(Sec. 114 of the Clean Air Act as amended (42 U.S.C. 1857c-9).)

(vi) The owner or operator shall retain at the source and make available for inspection by the Administrator for a minimum of 2 years records of all data needed to furnish the information required by paragraph (c) (2) (v) of this section: The records are to contain the following information:

(A) The vinyl chloride content found in all the samples required in paragraphs (c) (2) (i) and (c) (2) (ii) of this section, identified by the resin type and grade and the time and date of the sample, and

(B) The corresponding quantity of polyvinyl chloride resin processed by the stripper(s), identified by the resin type and grade and the time and date it represents.

(3) The owner or operator shall include in the report a record of the emissions from each reactor opening for which an emission limit is prescribed in § 61.64(a) (2). Emissions are to be determined in accordance with § 61.67(g) (5), except that emissions for each reactor are to be determined. For a reactor that is also used as a stripper, the determination may be made immediately following the stripping operation.

## APPENDIX A - REFERENCE METHODS

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### METHOD 106—DETERMINATION OF VINYL CHLORIDE 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, as there are many details that are beyond the scope of this presentation. Care must be exercised to prevent exposure of sampling personnel to vinyl chloride, a carcinogen.

#### 1. Principle and Applicability.

1.1 An integrated bag sample of stack gas containing vinyl chloride (chloroethene) is subjected to chromatographic analysis, using a flame ionization detector.

1.2 The method is applicable to the measurement of vinyl chloride in stack gases from ethylene dichloride, vinyl chloride and polyvinyl chloride manufacturing processes, except where the vinyl chloride is contained in particulate matter.

#### 2. Range and Sensitivity.

The lower limit of detection will vary according to the chromatograph used. Values reported include  $1 \times 10^{-7}$  mg and  $4 \times 10^{-7}$  mg.

3. Interferences. Acetaldehyde, which can occur in some vinyl chloride sources, will interfere with the vinyl chloride peak from the Chromasorb 102<sup>1</sup> column. See sections 4.3.2 and 6.4. If resolution of the vinyl chloride peak is still not satisfactory for a particular sample, then chromatograph parameters can be further altered with prior approval of the Administrator. If alteration of the chromatograph parameters fails to resolve the vinyl chloride peak, then supplemental confirmation of the vinyl chloride peak through an absolute analytical technique, such as mass spectroscopy, must be performed.

#### 4. Apparatus.

##### 4.1 Sampling (Figure 106-1).

4.1.1 Probe—Stainless steel, Pyrex glass, or Teflon tubing according to stack temperature, 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. A new unused piece is employed for each series of bag samples that constitutes an emission test.

4.1.3 Male (2) and female (2) stainless steel quick-connects, with ball checks (one pair without) located as shown in Figure 106-1.

4.1.4 Tedlar bags, 100 liter capacity—To contain sample. Teflon bags are not acceptable. Aluminized Mylar bags may be used, provided that the samples are analyzed within 24 hours of collection.

4.1.5 Rigid leakproof containers for 4.1.4, with covering to protect contents from sunlight.

4.1.6 Needle valve—To adjust sample flow rate.

4.1.7 Pump—Leak-free. Minimum capacity 2 liters per minute.

4.1.8 Charcoal tube—To prevent admission of vinyl chloride to atmosphere in 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 per minute.

4.1.10 Connecting tubing—Teflon, 6.4 mm outside diameter, to assemble sample train (Figure 106-1).

4.1.11 Pitot tube—Type B (or equivalent),

attached to the probe so that the sampling flow rate can be regulated proportional to the stack gas velocity.

##### 4.2 Sample recovery.

4.2.1 Tubing—Teflon, 6.4 mm outside diameter, to connect bag to gas chromatograph sample loop. A new unused piece is employed for each series of bag samples that constitutes an emission test, and is to be discarded upon conclusion of analysis of those bags.

##### 4.3 Analysis.

4.3.1 Gas chromatograph—With flame ionization detector, potentiometric strip chart recorder and 1.0 to 5.0 ml heated sampling loop in automatic sample valve.

4.3.2 Chromatographic column. Stainless steel, 2 m x 3.2 mm, containing 80/100 mesh Chromasorb 102. A secondary column of GE SF-96, 20 percent on 60/80 mesh AW Chromasorb P, stainless steel, 2 m x 3.2 mm or Porapak T, 80/100 mesh, stainless steel, 1 m x 3.2 mm is required if acetaldehyde is present. If used, a secondary column is placed after the Chromasorb 102 column. The combined columns should then be operated at 120° C.

4.3.3 Flow meters (2)—Rotameter type, 0 to 100 ml/min capacity, with flow control valves.

4.3.4 Gas regulators—For required gas cylinders.

4.3.5 Thermometer—Accurate to one degree centigrade, 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. Minimum capacity 100 ml/min.

##### 4.4 Calibration.

4.4.1 Tubing—Teflon, 6.4 mm outside diameter, separate pieces marked for each calibration concentration.

4.4.2 Tedlar bags—Sixteen-inch square size, separate bag marked for each calibration concentration.

4.4.3 Syringe—0.5 ml, gas tight.

4.4.4 Syringe—50 µl, gas tight.

4.4.5 Flow meter—Rotameter type, 0 to 1000 ml/min range accurate to  $\pm 1\%$ , to meter nitrogen in preparation of standard gas mixtures.

4.4.6 Stop watch—Of known accuracy, to time gas flow in preparation of standard gas mixtures.

5. Reagents. It is necessary that all reagents be of chromatographic grade.

##### 5.1 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, as required by the detector—Zero grade.

5.2 Calibration. Use one of the following options: either 5.2.1 and 5.2.2, or 5.2.3.

5.2.1 Vinyl chloride, 99.9+ percent. Pure vinyl chloride gas certified by the manufacturer to contain a minimum of 99.9 percent vinyl chloride for use in the preparation of standard gas mixtures in Section 7.1. If the gas manufacturer maintains a bulk cylinder supply of 99.9+ percent vinyl chloride, the certification analysis may have been performed on this supply rather than on each gas cylinder prepared from this bulk supply. The date of gas cylinder preparation and the certified analysis must have been affixed to the cylinder before shipment from the gas manufacturer to the buyer.

5.2.2 Nitrogen gas. Zero grade, for preparation of standard gas mixtures.

5.2.3 Cylinder standards (3). Gas mixture standards (50, 10, and 5 ppm vinyl chloride in nitrogen cylinders) for which the gas composition has been certified by the manufacturer. The manufacturer must have recommended a maximum shelf life for each cylinder so that the concentration does not

change greater than  $\pm 5$  percent from the certified value. The date of gas cylinder preparation, certified vinyl chloride concentration and recommended maximum shelf life must have been affixed to the cylinder before shipment from the gas manufacturer to the buyer. These gas mixture standards may be directly used to prepare a chromatograph calibration curve as described in section 7.3.

##### 5.2.3.1 Cylinder standards certification.

The concentration of vinyl chloride in nitrogen in each cylinder must have been certified by the manufacturer by a direct analysis of each cylinder using an analytical procedure that the manufacturer had calibrated on the day of cylinder analysis. The calibration of the analytical procedure shall, as a minimum, have utilized a three-point calibration curve. It is recommended that the manufacturer maintain two calibration standards and use these standards in the following way: (1) a high concentration standard (between 50 and 100 ppm) for preparation of a calibration curve by an appropriate dilution technique; (2) a low concentration standard (between 5 and 10 ppm) for verification of the dilution technique used.

##### 5.2.3.2 Establishment and verification of calibration standards.

The concentration of each calibration standard must have been established by the manufacturer using reliable procedures. Additionally, each calibration standard must have been verified by the manufacturer by one of the following procedures, and the agreement between the initially determined concentration value and the verification concentration value must be within  $\pm 5$  percent: (1) verification value determined by comparison with a calibrated vinyl chloride permeation tube, (2) verification value determined by comparison with a gas mixture prepared in accordance with the procedure described in section 7.1 and using 99.9+ percent vinyl chloride, or (3) verification value obtained by having the calibration standard analyzed by the National Bureau of Standards. All calibration standards must be renewed on a time interval consistent with the shelf life of the cylinder standards sold.

#### 6. Procedure.

6.1 Sampling. Assemble the sample train as in Figure 106-1. Perform a bag leak check according to Section 7.4. Observe 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 of 0.5 lpm. After a period of time sufficient to purge the line several times has elapsed, connect the vacuum line to the bag and evacuate the bag until the rotameter indicates no flow. Then reposition the sample and vacuum lines and begin the actual sampling, keeping the rate proportional to the stack velocity. Direct the gas exiting the rotameter away from sampling personnel. 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 the bag container from sunlight.

6.2 Sample storage. Sample bags must be kept out of direct sunlight. When at all possible analysis is to be performed within 24 hours, but in no case in excess of 72 hours of sample collection.

6.3 Sample recovery. With a piece of Teflon tubing identified for that bag, connect a bag inlet valve to the gas chromatograph sample valve. Switch the valve to withdraw gas from the bag through the sample loop. Plumb the equipment so the sample gas passes from the sample valve to the leak-free pump, and then to a charcoal tube, followed by a 0-100 ml/min rotameter with flow control valve.

6.4 Analysis. Set the column temperature

<sup>1</sup> Mention of trade names on specific products does not constitute endorsement by the Environmental Protection Agency.

to 100° C the detector temperature to 150° C, and the sample loop temperature to 70° 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 40 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 thirty seconds 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 laboratory pressure. From the chart, select the peak having the retention time corresponding to vinyl chloride, as determined in Section 7.2. Measure the peak area,  $A_m$ , by use of a disc integrator or a planimeter. Measure the peak height,  $H_m$ . Record  $A_m$ ,  $H_m$ , and the retention time. Repeat the injection at least two times or until two consecutive vinyl chloride peaks do not vary in area more than 5%. The average value for these two areas will be used to compute the bag concentration.

Compare the ratio of  $H_m$  to  $A_m$  for the vinyl chloride sample with the same ratio for the standard peak which is closest in height. As a guideline, if these ratios differ by more than 10%, the vinyl chloride peak may not be pure (possibly acetaldehyde is present) and the secondary column should be employed (see Section 4.3.2).

6.5 Measure the ambient temperature and barometric pressure near the bag. (Assume the relative humidity to be 100 percent.) From a water saturation vapor pressure table, determine and record the water vapor content of the bag.

#### 7. Calibration and Standards.

7.1 Preparation of vinyl chloride standard gas mixtures. Evacuate a sixteen-inch square Tedlar bag that has passed a leak check (described in Section 7.4) and meter in 5 liters of nitrogen. While the bag is filling, use the 0.5 ml syringe to inject 250  $\mu$ l of 99.9+ percent vinyl chloride through the wall of the bag. Upon withdrawing the syringe needle, immediately cover the resulting hole with a piece of adhesive tape. The bag now contains a vinyl chloride concentration of 50 ppm. In a like manner use the other syringe to prepare gas mixtures having 10 and 5 ppm vinyl chloride concentrations. Place each bag on a smooth surface and alternately depress opposite sides of the bag 50 times to further mix the gases. These gas mixture standards may be used for 10 days from the date of preparation, after which time preparation of new gas mixtures is required. (CAUTION.—Contamination may be a problem when a bag is reused if the new gas mixture standard contains a lower concentration than the previous gas mixture standard did.)

7.2 Determination of vinyl chloride retention time. This section can be performed simultaneously with Section 7.3. Establish chromatograph conditions identical with those in Section 6.3, above. Set attenuator to X 1 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 vinyl chloride. Maintain conditions. With the equipment plumbing arranged identically to Section 6.3, flush

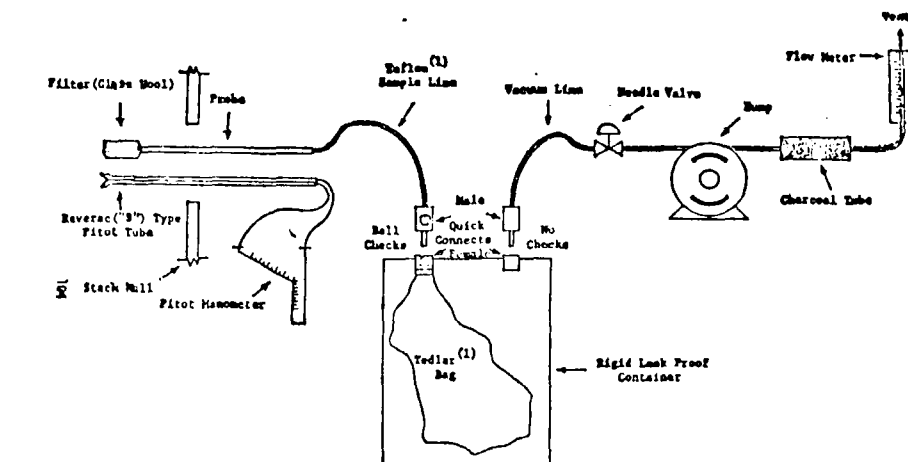


Figure 106-1. Integrated bag sampling train.

(1) Mention of trade names on specific products does not constitute endorsement by the Environmental Protection Agency.

the sample loop for 30 seconds at the rate of 100 ml/min with one of the vinyl chloride calibration mixtures and activate the sample valve. Record the injection time. Select the peak that corresponds to vinyl chloride. Measure the distance on the chart from the injection time to the time at which the peak maximum occurs. This quantity, divided by the chart speed, is defined as the retention time. Record.

7.3 Preparation of chromatograph calibration curve. Make a gas chromatographic measurement of each gas mixture standard (described in section 6.2.2 or 7.1) using conditions identical with those listed in sections 6.3 and 6.4. Flush the sampling loop for 30 seconds at the rate of 100 ml/min with each standard gas mixture and activate the sample valve. Record  $C_s$ , the concentration of vinyl chloride 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  $A_s$ , the peak area multiplied by the attenuator setting. Repeat until two injection areas are within 5 percent, then plot these points v.  $C_s$ . When the other concentrations have been plotted, draw a smooth curve through the points. Perform calibration daily, or before and after each set of bag samples, whichever is more frequent.

7.4 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 as follows. To leak check, connect a water manometer and pressurize the bag to 5-10 cm  $H_2O$  (2-4 in.  $H_2O$ ). Allow to stand for 10 minutes. 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 5-10 cm  $H_2O$  or 2-4 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 Determine the sample peak area as follows:

$$A_s = A_m A_f$$

Equation 106-1

where:

$A_s$  = The sample peak area.  
 $A_m$  = The measured peak area.  
 $A_f$  = The attenuation factor.

8.2 Vinyl chloride concentrations. From the calibration curve described in Section 7.3, above, select the value of  $C_s$  that corresponds to  $A_s$ , the sample peak area. Calculate  $C_b$  as follows:

$$C_b = \frac{C_s P_r T_i}{P_i T_r (1 - B_{w_i})}$$

Equation 106-2

Where:

$B_{w_i}$  = The water vapor content of the bag sample, as analyzed.  
 $C_b$  = The concentration of vinyl chloride in the bag sample in ppm.  
 $C_s$  = The concentration of vinyl chloride indicated by the gas chromatograph, in ppm.  
 $P_r$  = The reference pressure, the laboratory pressure recorded during calibration, mm Hg.  
 $T_i$  = The sample loop temperature on the absolute scale at the time of analysis, °K.  
 $P_i$  = The laboratory pressure at time of analysis, mm Hg.  
 $T_r$  = The reference temperature, the sample loop temperature recorded during calibration, °K.

#### 9. References.

1. Brown, D. W., Loy, E. W. and Stephenson, M. H. "Vinyl Chloride Monitoring Near the B. F. Goodrich Chemical Company in Louisville, Kentucky." Region IV, U.S. Environmental Protection Agency, Surveillance and Analysis Division, Athens, Georgia, June 24, 1974.
2. "Evaluation of A Collection and Analytical Procedure for Vinyl Chloride in Air," by G. D. Clayton and Associates, December 13, 1974. EPA Contract No. 68-02-1408, Task Order No. 2, EPA Report oN. 75-VOL-1.
3. "Standardization of Stationary Source Emission Method for Vinyl Chloride," by Midwest Research Institute, 1976. EPA Contract No. 68-02-1098, Task Order No. 7.

## RULES AND REGULATIONS

### Title 40—Protection of Environment

#### CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

##### SUBCHAPTER C—AIR PROGRAMS

(FRL 618-1)

#### PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

##### Standard for Vinyl Chloride

On December 24, 1975, under section 112 of the Clean Air Act, as amended (42 U.S.C. 1857), the Environmental Protection Agency (EPA) added vinyl chloride to the list of hazardous air pollutants (40 FR 59477) and proposed a national emission standard for it (40 FR 59532). The standard covers plants which manufacture ethylene dichloride, vinyl chloride, and/or polyvinyl chloride.

EPA decided to regulate vinyl chloride because it has been implicated as the causal agent of angiosarcoma and other serious disorders, both carcinogenic and noncarcinogenic, in people with occupational exposure and in animals with experimental exposure to vinyl chloride. Reasonable extrapolations from these findings cause concern that vinyl chloride may cause or contribute to the same or similar disorders at present ambient air levels. The purpose of the standard is to minimize vinyl chloride emissions from all known process and fugitive emission sources in ethylene dichloride-vinyl chloride and polyvinyl chloride plants to the level attainable with best available control technology. This will have the effect of furthering the protection of public health by minimizing the health risks to the people living in the vicinity of these plants and to any additional people who are exposed as a result of new construction.

Interested parties participated in the rulemaking by sending comments to EPA. The comments have been carefully considered, and where determined by the Administrator to be appropriate, changes have been made to the regulation as promulgated.

##### SUMMARY OF THE STANDARD

In ethylene dichloride-vinyl chloride plants, the standard limits vinyl chloride emissions from the ethylene dichloride and vinyl chloride formation and purification processes to 10 ppm. For the oxychlorination process, vinyl chloride emissions are limited to 0.2 g/kg of ethylene dichloride product.

In polyvinyl chloride plants, the standard limits vinyl chloride emissions from equipment preceding and including the stripper in the plant process flow to 10 ppm. Emissions from equipment following the stripper are to be controlled by stripping dispersion resins to 2000 ppm and other resins to 400 ppm, or by using equivalent controls. Vinyl chloride emissions from reactor opening are to be reduced to 0.02 g/kg polyvinyl chloride product.

In both ethylene dichloride-vinyl chloride and polyvinyl chloride plants, relief valve discharges and manual venting of gases are prohibited except under emergency conditions. Fugitive emissions

are required to be captured and controlled.

##### HEALTH AND ENVIRONMENTAL IMPACTS

EPA prepared a document entitled the *Quantitative Risk Assessment for Community Exposure to Vinyl Chloride* which estimates the risk from vinyl chloride exposure to populations living in the vicinity of vinyl chloride-emitting plants before and after implementation of controls to meet the standard. There are no dose-response data for the concentrations of vinyl chloride found in the ambient air. Therefore, assessments of risk at ambient levels of exposure were extrapolated from dose-response data from higher levels of exposure using both a linear model and a log-probit model. Extrapolations made with each of these models entailed using different sets of assumptions. Because different assumptions can be made in extrapolating to low doses, the health risks are reported in ranges.

It was estimated that 4.6 million people live within 5 miles of ethylene dichloride-vinyl chloride and polyvinyl chloride plants and that the average exposure around these plants before installation of controls to meet the standard is 17 parts per billion. The exposure levels for uncontrolled plants were calculated based on estimated 1974 emission levels. Using the linear dose-response model, EPA found that the rate of initiation of liver angiosarcoma among people living around uncontrolled plants is expected to range from less than one to ten cases of liver angiosarcoma per year of exposure to vinyl chloride. The log-probit model gave predictions that are 0.1 to 0.01 times this rate. This wide range is an indication of the uncertainties in extrapolation to low doses. Due to the long latency time observed in cancer cases resulting from vinyl chloride exposure, increases initiated by exposure this year will not be diagnosed until the 1990's or later. Vinyl chloride is also estimated to produce an equal number of primary cancers at other sites, for a total of somewhere between less than one and twenty cases of cancer per year of exposure among residents around plants. The number of these effects is expected to be reduced at least in proportion to the reduction in the ambient annual average vinyl chloride concentration, which is expected to be 5 percent of the uncontrolled levels after the standard is implemented.

Changes in the standard since proposal do not affect the level of control required. Thus, the environmental impact of the promulgated standard is, with one exception, the same as that described in Chapter 6 of Volume I of the *Standard Support and Environmental Impact Statement*. According to data submitted by the Society of Plastics Industry, Inc. (SPI), the impact on water consumption in the draft environmental impact statement was overstated. In estimating the impact on water consumption, EPA based its estimates on worst case conditions. That is, EPA assumed that those control systems with the

greatest water usage would be employed and that there would be no recycling of water. There is no regulation which would require water recycling. According to SPI, the control system utilizing the most water will not be used generally by the industry and economic factors will cause plants to recycle much of the water. Therefore, according to SPI the impact of the standard on water consumption will be negligible.

The environmental impacts of the promulgated standard may be summarized as follows: The primary environmental impacts of the standard are beneficial and will consist of vinyl chloride emission reductions of approximately 94 percent at ethylene dichloride-vinyl chloride plants and 95 percent at polyvinyl chloride plants. Percentage numbers for both source categories are based on an estimated 90 percent reduction in fugitive emissions and 1974 emission levels.

The potential secondary environmental impacts of the standard are either insignificant or will be minimized without additional action, except for one adverse impact. Hydrogen chloride is already emitted by process equipment at ethylene dichloride-vinyl chloride plants and by other petrochemical plants in the complexes where ethylene dichloride-vinyl chloride plants are typically located. An incinerator used to attain the standard at an ethylene dichloride-vinyl chloride plant could increase hydrogen chloride emissions by several fold. Typically, however, due to the corrosion problems which would otherwise occur both on plant property and in the community, plants use scrubbers to control already existing hydrogen chloride emissions. Hydrogen chloride emissions resulting from control of vinyl chloride emissions are expected to be controlled for the same reason. If even a moderately efficient scrubber (98 percent control) were used to control the hydrogen chloride emissions resulting from incineration of vinyl chloride emissions, the increase in hydrogen chloride emissions from a typical ethylene dichloride-vinyl chloride plant due to the standard would be reduced to 35 percent. However, EPA plans to further evaluate the need to control hydrogen chloride emissions, since diffusion model results indicate that under "worst-case" meteorological conditions, the hydrogen chloride emissions from the process equipment and the incinerator combined would cause maximum ambient concentrations of hydrogen chloride in the vicinity of ethylene dichloride-vinyl chloride plants to be in the same range or somewhat higher than existing foreign standards and National Academy of Sciences (NAS) guidelines for public exposure.

##### ECONOMIC IMPACT

In accordance with Executive Order 11821 and OMB circular A-107, EPA carefully evaluated the economic and inflationary impact of the proposed standard and alternative control levels and certified this in the preamble to the proposed standard. These impacts are

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discussed in Chapter 7 of Volume I of the *Standard Support and Environmental Impact Statement*. Comments on the proposed standard have resulted in only one major change in the economic impact analysis. EPA estimated that there would be four plant closures as a result of the promulgated standard. Of the four plants identified as possible closure candidates, one has given notice that it no longer produces polyvinyl chloride and the other three have indicated that they do not intend to close as a result of the standard.

The economic impacts of the promulgated standard may be summarized as follows: The total capital cost for existing plants to meet the standard is estimated to be \$198 million, of which \$15 million is for ethylene dichloride-vinyl chloride plants and \$183 million is for polyvinyl chloride plants. EPA estimates that these plants will have to spend \$70 million per year to maintain the required emission levels. In addition, the total capital cost for existing plants to meet the EPA's 1983 water effluent guideline limitations is expected to be \$83 million and the total annualized operation cost is \$17 million. The costs to the industry of meeting the OSHA standard cannot be quantified at this time, but they are expected to overlap to some degree with the costs to meet EPA's fugitive emission regulations. The costs of meeting the fugitive emission regulations are included in the total costs cited above for meeting the promulgated regulation. Broken out separately, the capital cost of meeting the fugitive emission regulations is \$37 million and the annualized cost is \$25 million.

The standard is not expected to deter construction of new ethylene dichloride-vinyl chloride plants or most types of new polyvinyl chloride plants. For one type of polyvinyl chloride plant (dispersion process) that represents 13 percent of the industry production, the standard would significantly deter the construction of smaller plants.

It is estimated that the price of polyvinyl chloride resins will rise by approximately 7.3 percent in order to maintain precontrol profitability and also to recover the total annualized control costs necessitated by the standard at ethylene dichloride-vinyl chloride plants and polyvinyl chloride plants. This increase is estimated to translate into a maximum consumer price increase in goods fabricated from polyvinyl chloride resins of approximately 3.5 percent. Recovery of effluent annualized costs plus maintenance of precontrol profitability is estimated to add approximately 2 percent to polyvinyl chloride resin prices and result in an additional maximum consumer price increase of 1 percent.

### PUBLIC PARTICIPATION

During the public comment period, 50 comment letters on the proposed standard were received. There were 24 from industry; 3 from environmental groups; 15 from Federal, State, and local agencies; and 8 from individual citizens. As required by section 112(b)(1)(B) of the

Act, a public hearing was held on the proposed standard on February 3, 1976, in Washington, D.C. Presentations were made by the Environmental Defense Fund, the Society of the Plastics Industry, Inc., Dow Chemical Company, Diamond Shamrock Corporation, and Air Products and Chemicals, Inc. Copies of the comment letters received, the public hearing record, 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 *Standard Support and Environmental Impact Statement, Emission Standard for Vinyl Chloride, Volume II*).

### SIGNIFICANT COMMENTS AND CHANGES TO THE PROPOSED REGULATION

(1) *Decision to list vinyl chloride as a hazardous air pollutant.* In general, the commenters did not contest EPA's decision to list vinyl chloride as a hazardous air pollutant. However, three commenters (two companies and one Federal agency) argued that EPA placed undue emphasis on factors suggesting that vinyl chloride presented a health risk and ignored factors suggesting that no significant risk was involved. Under section 112, however, EPA could remove vinyl chloride from the list of hazardous air pollutants only if information were presented to EPA that shows that vinyl chloride is clearly not a hazardous air pollutant. As discussed more fully in the comment summary, the commenters did not provide conclusive evidence that vinyl chloride is not a hazardous air pollutant which causes or contributes to death or serious illness, nor did they conclusively prove that the health risk factors emphasized by EPA were insignificant.

Several other commenters agreed with EPA's decision to list vinyl chloride as a hazardous air pollutant, but argued that EPA had overstated the health problem, the emission levels, and the projected ambient air concentrations around uncontrolled plants. With regard to the alleged overstated health problem, the commenters stated, for example, that the U.S. worker EPA discussed as having been exposed to vinyl chloride levels lower than those usually encountered in polyvinyl chloride production has been dropped from the National Institute of Occupational Safety and Health's listing of workers with angiosarcoma. EPA agrees that there are questions concerning the level of exposure and in some cases the pathology of these cases not involved directly in polyvinyl chloride and vinyl chloride production. These uncertainties are stated in the appropriate footnotes of the *Scientific and Technical Assessment Report on Vinyl Chloride and Polyvinyl Chloride (STAR)* where the angiosarcoma cases are listed. However, in spite of these uncertainties, in view of

the possible exposure patterns, these cases cannot be ignored in the evaluation of the potential public health problems.

With regard to the alleged overstated emission levels, the uncontrolled emission levels reported by EPA were based on 1974 data. This qualification was stated wherever emission data were presented. EPA recognizes that emissions have been reduced since that time, and stated this in the preamble to the proposed standard. EPA decided not to gather more recent data on emission levels, because these emission levels are expected to change, and gathering the data would take considerable time both on the part of EPA and on the part of industry. Since the purpose of the standard is to minimize emissions, these more current data would not affect the standard itself. The 1974 emission levels were also used in diffusion modeling to project maximum ambient air concentrations around uncontrolled plants. These maximum air concentrations would probably be lower if 1976 emission levels were used. This would reduce the relative impact of the standard below that described in the *Standard Support and Environmental Impact Statement*, but would not affect the basis of the standard itself.

(2) *Approach for Regulating Vinyl Chloride Under Section 112.* Two approaches other than using best available control technology were suggested by the commenters for regulating vinyl chloride under section 112. The first was to ban polyvinyl chloride products for which substitutes are currently available and to gradually phase out other polyvinyl chloride products as substitutes are developed.

In the preamble to the proposed standard EPA specified its reasons for not setting a zero emission limit for vinyl chloride, as follows: (1) There are beneficial uses of vinyl chloride products for which desirable substitutes are not readily available; (2) there are potentially adverse health and environmental impacts from substitutes which have not been thoroughly studied; (3) there are a number of employees, particularly in the fabrication industries, who would become at least temporarily unemployed; and (4) control technology is available which is capable of substantially reducing emissions of vinyl chloride into the atmosphere.

EPA agrees that substitutes do exist or could be manufactured for most polyvinyl chloride uses. However, in general, these substitutes do not have some of the more desirable characteristics of polyvinyl chloride, such as nonflammability. If vinyl chloride and polyvinyl chloride were banned, other substitutes with these more desirable characteristics would likely be developed. There is a risk that these substitutes would also have adverse health or environmental effects. Since control measures are available which can reduce vinyl chloride emissions by 90 percent or more, it does not seem prudent to reduce emissions by the remaining percentage and take the risk of introducing new untested chemicals into the environment.

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Another approach suggested by the commenters was to base the standard for each individual emission point on cost versus benefit. Several of the fugitive emission sources were named specifically as ones for which the costs of control were substantially higher than the benefits. Although EPA did determine a cost-benefit ratio for the controls required for a number of emission points, EPA does not believe such a ratio is an appropriate basis on which to set a standard. Section 111 of the Clean Air Act provides for the development of standards based on best control technology (considering costs). Even under section 111, however, standards are not based on a fine balancing of costs versus benefits. Instead, costs are considered in terms of the affordability of the control technology required to achieve a given emission level and the economic impact of possible standards on the industry in question. Unlike section 111, section 112 does not explicitly provide for consideration of costs, so it would clearly be inappropriate to consider costs to a greater extent under section 112 than would be done under section 111. As discussed in the preamble to the proposed standard for vinyl chloride, EPA believes costs may be considered under section 112, but only to a very limited extent; i.e., to assure that the costs of control technology are not grossly disproportionate to the amount of emission reduction achieved. In comparison with other emission points, the costs of controlling the fugitive emission sources mentioned by the commenters are relatively small compared with the amount of emission reduction achieved.

Several commenters recommended adding to the regulation a provision for excess emissions during startup, shutdown, and malfunction. EPA considered this comment, and decided that this addition is not necessary for the vinyl chloride standard. Startup and shutdown of the process has essentially no effect on emissions to the atmosphere for polyvinyl chloride production, and technology exists to avoid excess emissions during startup and shutdown at ethylene dichloride/vinyl chloride plants. We do not believe plants should be allowed to emit excess emissions during malfunctions, and therefore are requiring them to shut down immediately.

(3) *Selection of source categories.* In the preamble to the proposed standard EPA recognized that some small research and development facilities may exist where the emissions of vinyl chloride are insignificant and covering these facilities under the standard would be unnecessary and inappropriate. However, EPA did not have sufficient information available to clearly define which facilities should be excluded from the standard, and encouraged interested parties to submit such information during the comment period. Based on the information submitted, EPA decided to exempt polyvinyl chloride reactors and associated equipment from applicability of all parts of the standard if the reactors are used in research and development and have a

capacity of no more than 0.19 m<sup>3</sup> (50 gal). Reactors in this size range can generally be found in a laboratory, whereas the larger reactors are typically pilot scale facilities. Emissions from laboratory scale equipment are relatively small, and application of the controls required by the standard would be expensive and impractical. EPA also decided to exempt research and development facilities containing reactors greater than 0.19 m<sup>3</sup> (50 gal) and no more than 4.07 m<sup>3</sup> (1100 gal) in capacity from all parts of the standard except the 10 ppm limit for reactors, strippers, monomer recovery systems, and mixing, weighing and holding containers. EPA decided not to require these facilities to meet other parts of the standard because of the technical problems involved in doing so. For example, the standard for reactor opening is based in part on reducing the frequency of opening the reactor. Research and development reactors have to be opened after every batch for thorough cleaning. Also, stripping technology is developed individually for each resin in research and development equipment. Therefore, attainment of the stripping limitations in the research and development equipment would not always be possible. The 4.07 m<sup>3</sup> (1100 gal) figure was selected as an upper cut-off point because there are no commercial reactors smaller than this.

(4) *Emission limits.* The only major change in the emission limits between proposal and promulgation is the addition of a provision for emergency manual venting of vinyl chloride from reactors to the atmosphere. The proposed standard prohibited all manual venting to the atmosphere. In the preamble to the proposed standard, EPA invited interested persons to comment on whether permitting manual venting to the atmosphere could result in overall lower emissions. There are several methods available for preventing relief discharges from reactors, one of which is manual venting of part of the reactor contents for purposes of cooling and reduction in pressure within the reactor. The higher the temperature and pressure within the reactor, the greater the amount of vinyl chloride which has to be removed to bring the reactor under control. Manual venting can be done at a lower pressure than the pressure required to open the relief valve. For this reason manual venting can result in lower emissions than would occur by allowing the reactor to discharge through the relief valve. Furthermore, a manual vent valve is under the control of an operator and can be closed. A relief valve may become clogged with resin and not close. The result would be loss of all the reactor contents.

The contents of a reactor can be manually vented to a gasholder or other holding vessel. However, in some cases, such as during severe weather conditions, several reactors may be out of control at one time. There would be insufficient holding capacity under these conditions to manually vent the contents of all the reactors to a gasholder. Therefore, when all other measures to prevent relief valve discharges have been exhausted, manual

venting will be permitted as a last resort before the relief valve opens. The same notification procedures are required for manual venting to the atmosphere as are required for relief discharges.

There are several changes in the numerical emission limits in the promulgated standard. Except for the standard for reactor opening loss, these changes simply involve conversion to the International System of Units (SI). There was an error involved in the original calculation used to derive the standard for reactor opening. Correcting this error doubles the allowable emissions. It is emphasized that the change in this standard is a correction, and not a change in the intent for the degree of control required.

The proposed standard required the installation of a rupture disc beneath each relief valve to prevent leakage from the relief valve. A provision has been added to the promulgated standard so that a rupture disc is not required if the relief valve is tied into a process line or recovery system. In this case, any leakage from the relief valve would be contained.

The regulation for obtaining vinyl chloride samples has been changed to an operating procedure. The proposed standard stated that there were to be no emissions from taking the samples. Several commenters pointed out that the use of the word "no" would make this regulation impractical to enforce. Therefore, the promulgated standard specifies the operating procedure which EPA originally intended to be used to control this source. This revision is only a change in wording and does not represent a change in the level of the standard.

The regulation for taking samples has also been revised to apply only to samples containing at least 10 percent by weight vinyl chloride. This is consistent with the other parts of the standard which apply to equipment "in vinyl chloride service." "In vinyl chloride service" distinguishes between situations where vinyl chloride is clearly involved and situations where vinyl chloride is a minor component or contaminant, and as defined in promulgated § 61.61(1) means that a piece of equipment contains or contacts either a liquid that is at least 10 percent by weight vinyl chloride or a gas that is at least 10 percent by volume vinyl chloride.

The proposed standard required a vinyl chloride monitoring system for continuously measuring vinyl chloride levels both within the plant (for leak detection) and within stacks. The proposed standard did not outline required specifications for the monitoring system, except that it was to analyze the samples with gas chromatography, or if all hydrocarbons were assumed to be vinyl chloride, with infrared spectrophotometry, flame ion detection, or equivalent. It required that each plant submit a description of its monitoring system to EPA, so that EPA could determine whether it was acceptable or not. Comments were received indicating a need for EPA to specify some criteria for judging the acceptability of monitoring systems. The accuracy of the monitor-

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ing system would be related to the frequency of calibration. Therefore, EPA has included in the promulgated standard requirements for the frequency of calibration and procedures to be carried out in the calibration of the monitoring instruments.

The portable hydrocarbon detector required by the proposed standard was required to have a sensitivity of 5 ppm. Comments were received indicating that instruments in this sensitivity range are delicate and require continuing maintenance. The portable hydrocarbon detector is required for leak detection and for measuring vinyl chloride concentrations inside the equipment before opening it. A 5 ppm sensitivity is not needed in either case, and the required sensitivity has been changed to 10 ppm in the promulgated standard.

The proposed standard contained a single regulation for compressors. The promulgated standard has separate regulations for rotating and reciprocating compressors. This is consistent with having separate regulations for rotating and reciprocating pumps in both the proposed and promulgated standards.

Section 61.66 of the proposed standard provided for the use of equivalent methods of control which have been approved by EPA. The promulgated standard requires that the plant owner or operator submit a request for determination of equivalency within 30 days of the promulgation date if the alternative control method is intended as the initial means of control. The purpose of this is to provide time for EPA to evaluate the method before the plant has to be in compliance (for existing sources, 90 days after the promulgation date). EPA also suggests that this request for determination of equivalency be accompanied by a request for waiver of compliance pursuant to section 112(c)(1)(B)(ii) of the Act. The request for a waiver for compliance should provide for the case where EPA determines that a method is not equivalent and the plant needs to purchase other equipment. In no case will the waiver of compliance be extended beyond two years from the date of promulgation.

There are several wording clarifications which have been made in the promulgated standard. The definition for "in vinyl chloride service" (§ 61.61(1)) has been clarified by stating that it means equipment that contacts vinyl chloride as well as equipment that contains vinyl chloride. This would include such equipment as agitators.

Words have been added in §§ 61.62, 61.63, and 61.64 to clarify that the 10 ppm emission limits do not have to be met when equipment has already been opened in compliance with the regulation for opening of equipment. Equipment that has met the opening of equipment regulation can contain more than 10 ppm vinyl chloride and would be in violation of the standard if this statement were not included.

The requirements for stripping polyvinyl chloride resins to specified levels have been revised in §§ 61.64(e), 61.67

(g)(3)(ii), and 61.70(c)(2)(i) so that measurement of the vinyl chloride levels in the resins is to be made immediately after stripping is completed rather than as the resin is being transferred out of the stripper. This allows a plant to carry out operations in a stripper after stripping has been completed but before it is transferred out of the stripper. This is consistent with the original intent of the standard.

The regulation for loading and unloading lines in § 61.65(b)(1) has been revised to clarify that it applies only to lines that are disconnected after each loading or unloading operation. Permanently installed pipelines that are opened infrequently for inspection or maintenance, for example, are covered by the opening of equipment regulation rather than the loading and unloading line regulation.

The regulation for inprocess wastewater in the proposed standard could have been misinterpreted to require individual treatment of wastewater streams. Section 61.65(b)(9)(i) of the promulgated standard clarifies that wastewater streams that are required to be treated (i.e., those containing greater than 10 ppm vinyl chloride) can be combined to be treated. However, wastewater streams that contain greater than 10 ppm vinyl chloride cannot be combined with wastewater streams that contain less than 10 ppm vinyl chloride before treatment; i.e., dilution cannot be used to meet the standard.

The commenters recommended several changes in the emission limits which have not been incorporated into the promulgated standard. These are discussed in the following paragraphs.

It was recommended that the requirement for double mechanical seals on pumps, compressors, and agitators be removed because the single seals currently used on this equipment have small emissions and are more reliable than double mechanical seals. EPA is aware that each fugitive emission source, such as one pump, taken by itself causes relatively small emissions. Fugitive emissions considered as a whole are a significant source of emissions, however, and the intent of the standard is to reduce these. Double mechanical seal pumps are commonly used in the industry for emission reduction. Sealless pumps or equivalent systems are available as options to double mechanical seals.

The commenters recommended increasing the averaging time for the 10 ppm limits and the emission limits for reactor opening and stripping to 30 days. Some of the commenters apparently thought that the 10 ppm limits had to be met on an instantaneous basis. However, since the performance test for determining compliance consists of three runs for a minimum of an hour each, the averaging time for the 10 ppm limit is at least three hours. Increasing the averaging time to 30 days for any of the emission limits would permit higher peak emission levels. EPA has determined that this is neither desirable nor necessary.

Some commenters requested that the stripping levels for dispersion resins be

made the same as for other resins and others requested that they be made less stringent. EPA decided not to make the standard for stripping dispersion resins the same as for other resins because there is sufficient evidence to indicate that these resins are more difficult to strip than other resins. With regard to making the stripping levels for dispersion resins less stringent, only one of the eight manufacturers of dispersion resins specifically commented that the dispersion resin standard should be made less stringent. Only two of several grades of dispersion resins made by this company cannot meet the 2,000 ppm limit. The proposed standard takes into consideration that some resins are more difficult to strip than others by providing for averaging among different resins.

(5) *Testing, reporting, and record-keeping.* There are several relatively minor changes in the testing, reporting, and recordkeeping requirements. A provision has been added to § 61.67 which requires that stack gas samples taken with Test Method 106 are to be analyzed within 24 hours. This is consistent with the requirements in the proposed Test Method 106. The promulgated standard also specifies that in averaging the results of the three runs required by Test Method 106, a time-weighted average is to be used.

One commenter requested that the oxygen content and moisture content be specified for the 10 ppm concentration standards. The proposed standard specified that the vinyl chloride concentration is to be corrected to 10 percent oxygen (wet basis) if combustion is used as the control measure. In the promulgated standard, this requirement has been expanded to all control measures.

A provision has been added to the promulgated standard which states that if a reactor is also used as a stripper, the reactor opening emissions may be determined immediately following the stripping operation. If a reactor is also used as a stripper, the resin is in the reactor when it is opened. This means that vinyl chloride in the resin which has already been stripped to acceptable levels can escape from the resin and become part of the reactor opening loss. It is EPA's intent that once a resin has been stripped to the required levels, that additional controls are not required. Under the new provision, vinyl chloride escaping from the resin after it has been stripped to acceptable levels is not counted as part of the reactor opening loss.

A section requiring continuous monitoring of stack emissions has been added to the promulgated standard. The continuous monitoring of stack emissions was required in the proposed standard. The addition of a specific paragraph for emission monitoring serves only to clarify the requirement.

The standard has been revised so that the initial report requires a "description" rather than a "detailed description" of the equipment used to control fugitive emissions. Several commenters pointed out that a detailed description would contain proprietary information. EPA agrees that a detailed description in the

## RULES AND REGULATIONS

initial report is unnecessary. If additional information is needed, EPA can obtain it under section 114 of the Act and the plant can request confidential treatment in accordance with 40 CFR Part 2 for information it believes to be proprietary.

The proposed standard required that a semiannual report be submitted every 180 days. The promulgated standard specifies dates for the submittal of the reports. It also specifies that the first semiannual report does not have to be submitted until at least six months after the initial report is submitted.

The standard has been revised to eliminate the requirement to record the cause of any leak detected by the vinyl chloride detector, the action taken to repair the leak, and the amount of time required to repair the leak. EPA is concerned only that leaks are detected and repaired. That this has been done can be established by looking at the strip chart record of measurements made by the vinyl chloride detector. These records are still required for the portable hydrocarbon detector however.

Several commentators recommended that the companies be allowed an extra two weeks to submit to EPA data from the initial performance test. They also recommended that they submit the data by regular mail rather than registered mail. EPA has not adopted either of these recommendations. A source is supposed to be in compliance with the standard within 90 days of the promulgation of the standard. The standard requires that the emission tests be done within the 90 day period, and permits an extra 30 days for determination of results. The purpose of using registered mail is to document the fact that emission data have been sent and received. This way if the results are lost in the mail, there will be no question that they were sent.

(6) *Test method.* Test Method 106 has been changed to recognize that on a gas chromatograph equipped with a Chromosorb 102 column, acetaldehyde may interfere with the vinyl chloride peak. When a sample is expected to contain acetaldehyde, a secondary column as described in section 4.3.2 must be employed. Mass spectroscopy or another absolute analytical technique is required to confirm the vinyl chloride peak obtained with the gas chromatograph, only if peak resolution with the secondary column is not successful.

In section 4.1.4, aluminized Mylar bags can be substituted for Tedlar bags. EPA now has data to allow this substitution, provided that the samples are analyzed within 24 hours of collection.

In section 5.1.3 of Test Method 106 the requirement to use "oxygen gas" has been replaced with "oxygen gas or air, as required by the detector." Several commentators stated that most gas chromatographs are designed to use hydrogen and air for their flame detectors. When used in this way, they are capable of detecting 0.5 ppm vinyl chloride in air. This is sensitive enough for monitoring the 10 ppm emission limits stipulated in the standard.

In section 6.4 of Test Method 106 the requirement for an automatic integrator has been replaced with a requirement for a disc integrator or planimeter for measuring peak area. This change is in response to a comment which states that automatic integrators are unnecessarily elaborate and expensive.

A new section 6.5 has been added to Test Method 106 which requires determination of the water vapor content of the sampling bag by measuring the ambient temperature and pressure near the bag. The vinyl chloride concentration of the bag can then be reported on a dry basis. A provision for checking the rigid container for leaks has been added to section 7.4 of Test Method 106.

The only change in Test Method 107 is the provision in Section 5.3.2 for use of Carbopak C as well as Carbopak A.

**AUTHORITY:** Section 112 of the Clean Air Act as added by sec. 4(a) of Pub. L. 91-604, 84 Stat. 1685 (42 U.S.C. 1857c-7); Section 114 of the Clean Air Act, as added by sec. 4(a) of Pub. L. 91-604, 84 Stat. 1687, and amended by Pub. L. 93-319, sec. 6(a)(4), 88 Stat. 259 (42 U.S.C. 1857c-9); Section 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(a)).

Dated: October 12, 1976.

JOHN QUARLES,  
Acting Administrator.

FEDERAL REGISTER, VOL. 41, NO. 205-

-THURSDAY, OCTOBER 21, 1976

## PROPOSED RULES

### ENVIRONMENTAL PROTECTION AGENCY

[40 CFR Part 61]

[FRL 728-5]

#### VINYL CHLORIDE

#### National Emission Standards for Hazardous Air Pollutants

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

**SUMMARY:** The proposed amendments are being made to the vinyl chloride standard which has promulgated October 21, 1976, and would apply to new and existing ethylene dichloride, vinyl chloride, and polyvinyl chloride plants. The standard and the proposed amendments implement the Clean Air Act and are based on the Administrator's determination that vinyl chloride is a hazardous air pollutant. The intended effect of the proposed amendments is to require improved effectiveness of control technology at existing plants, impose more stringent emission limits on new sources, and prohibit an emission increase within the vicinity of an existing source due to the construction of a new source.

**DATES:** Comments must be received on or before August 1, 1977.

**ADDRESSES:** Comments should be submitted (preferably in triplicate) to the Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina, Attention: Mr. Don R. Goodwin.

All public comments received may be inspected and copied at the 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, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Telephone No. 919-688-8146, ext. 271.

**SUPPLEMENTARY INFORMATION:**

#### BACKGROUND

On October 21, 1976, EPA promulgated a standard for vinyl chloride under the authority of section 112(b)(1)(B) of the Clean Air Act, as amended (41 FR 46561). The standard applies to ethylene dichloride, vinyl chloride, and polyvinyl chloride plants.

On November 19, 1976, the Environmental Defense Fund (EDF) petitioned the United States Court of Appeals for the District of Columbia Circuit to review the standard. Motions to intervene were subsequently filed on behalf of the Society of the Plastics Industry, Inc., the Goodyear Tire and Rubber Company and Air Products and Chemicals, Inc., and were granted by order of the Court on January 18, 1977. On March 24, 1977, EDF and EPA moved to dismiss the proceedings in view of a settlement agreement requiring EPA to take certain

additional actions. These include a re-statement of EPA's policy for regulating carcinogens under section 112 of the Clean Air Act; the proposal of amendments which would require increased efficiency of existing control equipment, require more stringent control at new sources, and prohibit increases in emissions within the vicinity of an existing source due to new construction; and the initiation of a review of the vinyl chloride standard three years after the promulgation of the amendments.

#### ZERO EMISSION GOAL

The vinyl chloride standard has been criticized for allegedly placing unwarranted emphasis on technological rather than health considerations. Although EPA disagrees with this criticism, it seems appropriate to restate EPA's approach to the regulation of carcinogens in general and under Section 112 of the Clean Air Act, and to explain how the vinyl chloride standard and the proposed amendments are consistent with this approach and with the protection of public health.

On May 25, 1976, EPA published interim procedures and guidelines for health risk and economic impact assessments of suspected carcinogens (41 FR 21402), which define EPA's approach to regulatory action for suspect carcinogens. As indicated in that publication, there are two steps involved in the decision-making process with regard to the regulation of a potential carcinogen. Although different EPA statutory authorities impose different requirements, in general two decisions must be made with regard to each potential carcinogen. The first decision is whether a particular substance constitutes a cancer risk. The second decision is what regulatory action, if any, should be taken to reduce that risk.

In deciding whether a cancer risk exists, EPA will consider a substance a presumptive cancer risk when it causes a statistically significant excess incidence of benign or malignant tumors in humans or animals. In the case of vinyl chloride, EPA evaluated all available data and concluded that a cancer risk exists. In deciding how and whether to regulate, EPA examined section 112 of the Clean Air Act. Section 112 of the Act requires that emission standards be set "at the level which in the judgment of the Administrator provides an ample margin of safety to protect the public health from such hazardous air pollutants." This requirement appears to assume that each pollutant regulated will have a threshold level of effects below which no health effects will occur. As explained in the documentation for the current standard (40 FR 59532, December 24, 1975; 41 FR 46560, October 21, 1976), it has not been possible to determine if there is a threshold level of effects for vinyl chloride and it is not certain that such a threshold may be determined in the near future. In the absence of strong evidence to the contrary, then, the only level of vinyl chloride which would appear to be absolutely protective of health is zero, which may

be achievable only by banning vinyl chloride emissions completely. That, in turn, would require closing the entire industry. As explained in the earlier rulemaking it is not clear that Congress would have intended this result, so instead EPA required the lowest level achievable using technological means. (See 40 FR 59534 and 41 FR 46562).

In order to insure that the standard continues to approach the only level of emissions which is known to be absolutely protective of health, namely zero emissions, EPA is proposing amendments which require more efficient use of existing control technology at existing plants and more effective controls at new plants, and which encourage technology to reach this goal without banning vinyl chloride.

#### MORE STRINGENT STANDARDS FOR EXISTING SOURCES

EPA is proposing amendments which would require sources presently subject to a 10 ppm emission limit to reduce emissions to 5 ppm within three years of promulgation of the amendments. The affected sources include ethylene dichloride purification; vinyl chloride formation and purification; reactors, strippers; mixing, weighing, and holding containers; monomer recovery systems; and fugitive emissions which have been captured in accordance with the existing regulation.\* If the owner or operator of a source believed that a control system would not be capable of meeting the 5 ppm limit, he would be able to request that the Administrator approve an interim emission limit for that source. Such requests would have to be made one year before the compliance date. In requesting an interim emission limit, the owner or operator would have to submit supportive data and meet with EPA to discuss his particular problems in attaining compliance. The meeting would be announced in the FEDERAL REGISTER and any interested party would be allowed to attend and submit written or oral comments. If an interim emission limit were granted to the source, the required emission level would be specified in a written notification from EPA and in the FEDERAL REGISTER. Each source granted an interim emission limit would be reviewed every three years to determine whether emissions could be reduced to 5 ppm, or at least to a lower interim emission limit.

In proposing the reduction from 10 to 5 ppm, it is not EPA's intent that a control system which has been installed to

\*As an explanatory note, paragraph (b) of § 61.65 contains nine fugitive emission regulations. For several of these, the fugitive emissions are required to be captured and ducted to a control device meeting 10 ppm. According to the proposed amendments, the emissions from this control device would have to be reduced to 5 ppm in the same way any other source currently required to meet 10 ppm would have to do. Rather than incorporating both the 5 and 10 ppm emission limits in each paragraph in § 61.65(b), a separate paragraph (c) containing these emission limits is being added to § 61.65. All the other paragraphs in (b) are cross-referenced in paragraph (c).

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meet the 10 ppm emission limit be removed and replaced with another more efficient control system or that a second control system be added behind the first control system. The purpose of the proposed amendment is to force owners and operators to maximize the effectiveness of existing control systems.

### MORE STRINGENT STANDARDS FOR NEW SOURCES

The proposed amendments would also require more stringent controls for new sources; i.e., sources for which construction is commenced after the date of proposal of these amendments. According to §61.02 of the General Provisions, "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 contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

New sources of types which would be subject to the 10 ppm emission limit under the current standard would be required under the amendments to meet a 5 ppm emission limit at the time of startup. With new sources there would be no provision allowing requests for EPA approval of an interim emission limit. New sources would be required to meet the more stringent emission limit at the time of startup, because they have an opportunity to design their equipment to meet the 5 ppm emission limit at the time construction is commenced. Existing sources, on the other hand, require time to maximize the effectiveness of their control systems.

The proposed amendment would also require ethylene dichloride-vinyl chloride plants to control emissions from new oxychlorination reactors to 5 ppm. This requirement is based on installation of a recycling and oxygen feed system with an incinerator or equivalent control device. The current standard limits emissions from the oxychlorination reactor to 0.2 g/kg (0.0002 lb/lb) of the 100 percent ethylene dichloride product from the oxychlorination reactor. This emission limit can be met by changing process parameters, rather than installing a control device. During the development of the current standard EPA considered requiring existing sources to control emissions with an incinerator or equivalent technology, but rejected this approach because a large quantity of fuel would be required to reduce emissions from a relatively small source. An existing oxychlorination reactor typically has a large volume, low hydrocarbon effluent gas stream, and large quantities of supplemental fuels would be required for combustion of its emissions.

A new plant can reduce the volume of its effluent gas stream and make it more concentrated by recycling the gas stream and using oxygen instead of air to feed into the process. (3, 4) the current standard was not based on this technology because it was not considered feasible to retrofit existing plants so that they could use oxygen instead of air. The re-

cycling and oxygen feed methodology is considered feasible for new oxychlorination reactors because it can be incorporated at the time of construction. Since the use of this technology would eliminate the supplemental fuel problem referred to above, it is EPA's judgment that new oxychlorination reactors should be controlled to the same extent that is proposed for other emission sources.

The proposed amendment also includes a more stringent emission limit for new polyvinyl chloride resins being processed in equipment following the stripping operation. That is, the amendment would apply to resins for which production for the purpose of marketing was commenced after the proposal of the amendment. The amendment would require all new resins except new dispersion resins to be stripped to 100 ppm and new dispersion resins to be stripped to 500 ppm. These limits for new products would be one-fourth of the limits contained in the standard for existing products. Consistent with the current standard, the amendment would permit the use of control devices rather than stripping technology to meet the emission limit. In this case equipment being used to process all new resins except new dispersion resins would have to be controlled to 0.01 kg/kg product and the equipment used for new dispersion resins would have to be controlled to 0.05 kg/kg product.

A "new source" is defined in 40 CFR 61.02 as a stationary source, the construction or modification of which is commenced after proposal of a standard. There was some question based on this definition as to whether the amendment to the stripping standard for new sources should apply to new polyvinyl chloride resins or the installation of new equipment following the stripper. If the applicability of the amendment for new sources were based on the installation of new equipment following the stripper, it would be difficult to determine what constitutes a new source at an existing plant. This is based on the reasoning that the stripping standard requires that all equipment following the stripper in the process be controlled as a unit. The series of equipment following the stripper includes pumps and conveying equipment which might be expected to be replaced on a frequent and routine basis. Replacing one of these pieces of equipment would in effect cause the whole series of equipment following the stripper to have to meet the standard for new sources. In other words, all resins processed in the series of the equipment would have to meet the lower standard even though only a minor part of the equipment had been replaced.

EPA decided that a more reasonable and direct approach was to make the proposed amendment apply to the production of new polyvinyl chloride resins. This is based on the reasoning that emissions from the equipment following the stripper are a function of the amount of vinyl chloride left in the resin after the stripping operation is completed; i.e., the resin is the source of the emissions

rather than the equipment. The same equipment can be used to process different resin grades. Variations in the emissions from the equipment are a function of the resin being processed rather than the characteristics of the equipment. The control technology which is used for the equipment following the stripper is likewise more directly linked to the resin than the equipment. Stripping is used to control the emissions due to the vinyl chloride in the resin before the resin is processed in the equipment.

Before the hazards of vinyl chloride became known, stripping technology was employed by polyvinyl chloride manufacturers to recover raw materials for economic purposes. As a result of a standard promulgated by the Occupational Safety and Health Administration (39 FR 35890), some companies investigated improvements in stripping methodology for emission control purposes. (1)

Optimum stripping consists of a set of operating conditions which must be developed experimentally on an individual basis for the many resins. In developing the current standard, EPA recognized that stripping technology for dispersion resins had not been refined to the same extent as it had been for other resins and that there was more difficulty in stripping dispersion resins than other resins. For this reason a less stringent emission limit was established for dispersion resins. Dispersion resins are permitted a higher emission limit under the proposed amendment for the same reason.

EPA believes that for some resins, companies have already developed stripping technology which would meet the proposed amendment. (2) For other resins, the proposed standard would require additional improvement in stripping technology. If stripping technology has not been developed to the extent necessary to meet the proposed amendment for a particular resin, the manufacturer would have the option of developing the technology or not producing the resin.

The current standard, unlike the proposed amendment, was not based on the premise that an owner or operator would have the option of not producing a particular resin. It is EPA's judgment that the owner or operator making a new product has more freedom of choice than the owner or operator already making a particular product in selecting those resins which are to be produced. EPA's standard would be included in the variables under consideration when decisions are being made as to which resins are to be produced.

The proposed amendment would apply to any new source, whether it constituted replacement of an existing source in an existing plant, the expansion of an existing plant, or part of an entirely new plant. That is, if a new oxychlorination reactor or a new polyvinyl chloride reactor were installed at an existing plant, it would be subject to the emission limits for new sources. This means that as existing sources are gradually replaced with new sources in an existing plant,

## PROPOSED RULES

the overall emission level from that existing plant would be reduced.

### EMISSION OFFSET

Because the present vinyl chloride standard focuses on reducing emissions rather than attaining a particular ambient air quality concentration, there is no provision for limiting the size of plants or the clustering of plants in a geographical area. The doubling of the size of an existing plant or the construction of a new plant beside an existing plant would considerably increase the ambient air concentrations of vinyl chloride in the vicinity of the plant(s) even if the vinyl chloride standard was met. EPA determined at the time of promulgation of the current standard that the costs of prohibiting the production of vinyl chloride and polyvinyl chloride were too high and the continued operation of existing plants should be allowed. EPA believes, however, that the standard should include a mechanism for prohibiting an increase in ambient concentrations of vinyl chloride due to new construction in areas where existing sources are already located.

Accordingly, EPA is proposing an amendment which would prohibit an increase in emissions within 8 kilometers (km) (approximately five miles) of an existing source due to the construction of a new emission source. This means that if a new source were added to an existing plant, the increase in emissions due to that new source would have to be offset by a reduction in emissions from other existing sources within that plant or at other plants within 8 km of the construction site of the new source. Similarly, a new plant could not be constructed within 8 km of an existing plant(s) unless the emission increase due to the new plant were offset by an emission reduction at the existing plant or plants. This provision may result in few existing plants being expanded and few new plants being constructed in the vicinity of existing plants. However, the proposed amendment does not preclude this possibility.

The offset provision would apply only to new construction which results in an increase in production rate. Replacing or adding equipment such as pumps, compressors, agitators, sampling equipment and unloading hoses is a routine practice at existing plants. Additions of equipment of this nature would, in and of itself, be expected to result in little, if any, increase in emissions. In EPA's judgment, a plant should not be required to prove this fact each time one of these pieces of equipment is added. The addition of this type of equipment in conjunction with major process equipment, however, is likely to result in both an increase in emissions as well as an increase in production rate, and is therefore covered by the offset provision.

If the offset provision were adopted, the reduction in emissions could be achieved in the production rate of an existing source or sources. The baseline emission rate would be determined based on the maximum production rate which

had been attained by each existing source. The allowable emission rate for each source would be based on the maximum production rate at which that source would be operated in the future.

Also, if the emissions from an existing source were already below the emission limit applicable to it, the proposed amendment would give the source credit for the difference between the emission limit and the actual emission level. That is the baseline emission rate would be based on the standard rather than on an emission test. It is EPA's judgment that this is a more equitable approach than penalizing a source which has already taken measures to reduce emissions below the standard. Such a source would have less room for further reducing emissions.

The emission limits applicable to both the existing and new sources involved in the offset arrangement would be contained in the approval of new construction granted by the Administrator under 40 CFR 61.08.

EPA believes that a policy of no net increase in emissions due to new construction is justified because of the hazardous nature of vinyl chloride. However, EPA recognizes the potential difficulties in implementing such a policy and interested persons are urged to submit comments and factual information relating to this policy.

### REVIEW OF STANDARD

EPA plans to undertake a full-scale review of Subpart F of 40 CFR Part 61 beginning three years from the promulgation of any amendments. In the study EPA will review information concerning technological advances in the control of vinyl chloride emissions to determine what further changes might then be appropriate to move toward the goal of zero vinyl chloride emissions. EPA will also consider recent health data to determine whether the approach for regulating vinyl chloride should be altered.

### ENVIRONMENTAL IMPACT

The proposed amendment, in contrast to the current standard, would encourage the development of new technology and improvements in existing technology and would have the following three positive environmental impacts: (1) further reduction of emissions at existing plants, (2) no increase in emissions within 8 km of an existing source, and (3) lower emissions from new sources than would be accomplished through the current standard regardless of the construction site. These environmental impacts would provide progress toward the ultimate goal of zero emissions without banning vinyl chloride, and in the process would provide additional protection of public health by further minimizing the health risks to the people living in the vicinity of existing plants and to any additional people who are exposed as a result of new construction.

Specifically, for those existing sources which are currently subject to a 10 ppm emission limit, emissions would be reduced by half within three years after the promulgation date of these amendments. At both an existing average-sized

ethylene dichloride-vinyl chloride plant and an existing average-sized polyvinyl chloride plant, which contain other sources than the ones required to meet a 5 ppm emission limit, it is estimated this will have the effect of reducing total emissions by less than one percent. Emissions at existing plants would be further reduced as existing oxychlorination reactors are replaced with new oxychlorination reactors and as new polyvinyl chloride resins are produced to replace existing ones.

Under the proposed amendment, emissions from new plants would be considerably lower than they would be under the current standard. For a typical new average-sized ethylene dichloride-vinyl chloride plant ( $318 \times 10^6$  kg/yr or  $700 \times 10^6$  lb/yr produced), the hourly emissions would be 5.1 kg (11.5 lb) instead of 10.3 kg (23.1 lb). For a typical new average-sized dispersion polyvinyl chloride plant ( $46 \times 10^6$  kg/yr or  $100 \times 10^6$  lb/yr production), the emissions would be about 9 kg/hr (20 lb/hr) instead of 17.5 kg/hr (39 lb/hr) and for a typical new average-sized suspension polyvinyl chloride ( $68 \times 10^6$  kg/yr or  $150 \times 10^6$  lb/yr production) the emissions would be 13.5 kg/hr (30 lb/hr) instead of 16 kg/hr (36 lb/hr). These emissions are calculated based on the emission factors published in the documentation for the existing standard. (1) Ambient air concentrations are expected to be reduced proportionately.

The only negative environmental impact would be an increase in hydrogen chloride emissions at ethylene dichloride-vinyl chloride plants if incineration were used to control emissions from new oxychlorination reactors. However, due to the corrosion problems which would otherwise occur on plant property and in the community, plants are expected to use scrubbers to control the hydrogen chloride emissions. The proposed amendment is not expected to have a significant impact on energy consumption.

### ECONOMIC IMPACT

The potential economic impacts of the proposed standard are:

(1) Costs for research and development of improved methodology for operation of existing control technology so that it can be used to meet the 5 ppm emission limit.

(2) Costs for research and development of improved stripping techniques to meet the standard for new polyvinyl chloride resins.

(3) Cost of research and development or licensing for converting over to the oxygen system for a new oxychlorination reactor.

(4) Possibly increased transportation costs of raw materials in the case that the offset policy results in the construction of a new plant farther from an existing plant than it otherwise would have been.

(5) Costs of building a new plant more than 8 km from an existing plant in the event that the offset requirement precluded the expansion of an existing plant.

## PROPOSED RULES

(6) Delay in the production of a particular resin due to time spent developing stripping technology for that resin.

(7) No growth in the production of a particular resin due to the inability to strip that resin to required levels.

The types of costs which have been named would be difficult to quantify. The costs would be expected to vary considerably from one plant to another depending on the amount of research and development than had already been done, the extent to which technology could be transferred from other plants and processes, and the plans for new construction.

One area in which cost estimates can be generated is the use of an oxygen-recycle oxychlorination process as opposed to an air-based system. The proposed amendment does not require the use of the oxygen-recycle system, but many plants would be expected to employ this system to avoid the high costs of incinerating the high volume gas stream from a typical air-based system. The primary cost of using the oxygen-recycle system is the cost of the oxygen itself. The cost of the oxygen for a particular plant would depend on whether the plant was located where there is a considerable demand for both the oxygen and nitrogen products of air separation. According to one recent article, if it is assumed that such a demand exists, the cost of the oxygen (\$14.34/ton) would be approximately equivalent to the cost of compressing air for use in the air-based system. (1) Another report in which this assumption was not made and the economics of the air and oxygen systems were being compared, it was concluded that overall production economics "favor the oxygen process even if vent gas incineration would not be required for an air-based plant since the sum of all remaining advantages offered by oxygen-based plant operation more than outweighs the incremental cost for the oxygen feed." (2)

**Miscellaneous:** The Administrator invites comments on all aspects of the proposed amendments.

(Section 112 of the Clean Air Act, sec. 4(a) of Pub. L. 91-604, 84 Stat. 1685 (42 U.S.C. 1857c-7) and section 301(a) of the Clean Air Act, sec. 2 of Pub. L. No. 90-148, 84 Stat. 504 as amended by sec. (15) (c) (2) of Pub. L. 91-604, 84 Stat. 1713 (42 U.S.C. 1857 g(a)). Secs. 61.67 and 61.68 also proposed under the authority of section 114 of the Clean Air Act, as added by sec. 4(a) of Pub. L. 91-604, 84 Stat. 1687 and amended by Pub. L. 93-319, sec. 6(a) (4), 88 Stat. 259 (42 U.S.C. 1857c-9).)

**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: May 27, 1977.

DOUGLAS M. COSTLE,  
Administrator.

### REFERENCES

(1) *Standard Support and Environmental Impact Statement: Emission Standard for Vinyl Chloride*, EPA-450 12-75-009, October, 1975.

(2) "Goodrich Reports Impressive Progress in Solving Vinyl Chloride Problem," *American Paint and Coatings Journal*, Vol. 60, No. 31, January 12, 1976, p. 24.

(3) E. W. Wimer and R. E. Feathers, "Oxygen Gives Low Cost VCM," *Hydrocarbon Processing*, March 1976, pp. 81-84.

(4) Peter Reich, "Air or Oxygen For VCM?," *Hydrocarbon Processing*, March, 1976, pp. 85-89.

It is proposed that Subpart F of 40 CFR Part 61 be amended as follows:

1. In § 61.08, paragraph (b) is revised to read as follows:

§ 61.08 Approval by the Administrator.

(b) If the Administrator determines that a stationary source for which an application pursuant to § 61.07 was submitted will not, if properly operated, cause emissions in violation of the standard or violation of § 61.73, he will approve the construction or modification of such source.

2. Section 61.62 is revised to read as follows:

§ 61.62 Emission standard for ethylene dichloride plants.

An owner or operator of an ethylene dichloride plant shall comply with the requirements of this section and § 61.65.

(a) Ethylene dichloride purification: Except as provided in § 61.65(a), the concentration of vinyl chloride in all exhaust gases discharged to the atmosphere from any equipment used in ethylene dichloride purification is not to exceed the appropriate emission limit as follows:

(1) Each source for which construction had commenced on or before (date of proposal of these amendments), 10 ppm until (date three years after promulgation of these amendments) and 5 ppm after (date three years after the promulgation of these amendments).

(2) Each source for which construction commenced after June 2, 1977, 5 ppm.

(b) Oxychlorination reactor: Except as provided in § 61.65(a), emissions of vinyl chloride to the atmosphere are not to exceed the appropriate emission limit as follows:

(1) Each source for which construction had commenced on or before (date of proposal of these amendments), 0.2 g/kg (0.0002 lb/lb) of the 100 percent ethylene dichloride product from the oxychlorination reactor.

(2) Each source for which construction commenced after June 2, 1977, 5 ppm.

(c) The requirements of this section do not apply to equipment that has been opened, is out of operation and met the requirement in § 61.65(b) (6) (i) before being opened.

3. Section 61.63 is revised to read as follows:

§ 61.63 Emission standard for vinyl chloride plants.

An owner or operator of a vinyl chloride plant shall comply with the requirements of this section and § 61.65.

(a) Vinyl chloride formation and purification: Except as provided in § 61.65(a), the concentration of vinyl chloride in all exhaust gases discharged to the atmosphere from any equipment used in vinyl chloride formation and/or purification is not to exceed the appropriate emission limit as follows:

(1) Each source, for which construction had commenced on or before June 2, 1977, 10 ppm until (date three years after promulgation of these amendments) and 5 ppm after (date three years after promulgation of these amendments).

(2) Each source for which construction commenced after June 2, 1977, 5 ppm.

(b) The requirements of this section do not apply to equipment that has been opened, is out of operation, and met the requirement in § 61.65(b) (6) (i) before being opened.

4. Section 61.64 is amended by revising paragraphs (a) (1), (b), (c), (d) and (e) and by adding paragraph (f) as follows:

§ 61.64 Emission standard for polyvinyl chloride plants.

An owner or operator of a polyvinyl chloride plant shall comply with the requirements of this section and § 61.65.

(a) Reactor: The following requirements apply to reactors:

(1) Except as provided in paragraph (a) (2) of this section and § 61.65(a), the concentration of vinyl chloride in all exhaust gases discharged to the atmosphere from each reactor is not to exceed the appropriate emission limit as follows:

(i) Each source for which construction had commenced on or before June 2, 1977 10 ppm until (date three years after promulgation of these amendments) and 5 ppm after (date three years after promulgation of these amendments).

(ii) Each source for which construction commenced after June 2, 1977, 5 ppm.

(b) Stripper: Except as provided in § 61.65(a), the concentration of vinyl chloride in all exhaust gases discharged to the atmosphere from each stripper is not to exceed the appropriate emission limit as follows:

(1) Each source for which construction had commenced on or before June 2, 1977 10 ppm until (date three years after promulgation of these amendments) and 5 ppm after (date three years after final promulgation of these amendments).

(2) Each source for which construction commenced after June 2, 1977, 5 ppm.

(c) Mixing, weighting, and holding containers: Except as provided in § 61.65(a), the concentration of vinyl chloride in all exhaust gases discharged to the atmosphere from each mixing, weighing, or holding container in vinyl chloride service which precedes the stripper (or the reactor if the plant has no stripper) in the plant process flow is not to exceed the appropriate emission limit as follows:

(1) Each source, for which construction had commenced on or before (date

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of proposal of these amendments), 10 ppm until (date three years after promulgation of these amendments) and 5 ppm after (date three years after promulgation of these amendments).

(2) Each source for which construction commenced after June 2, 1977, 5 ppm.

(d) Monomer recovery system. Except as provided in § 61.65(a), the concentration of vinyl chloride in all exhaust gases discharged to the atmosphere from each monomer recovery system is not to exceed the appropriate concentration as follows:

(1) Each source for which construction had commenced on or before (date of proposal of these amendments), 10 ppm until (date three years after promulgation of these amendments) and 5 ppm after (date three years after promulgation of these amendments).

(2) Each source for which construction commenced after June 2, 1977, 5 ppm.

(e) Sources following the stripper(s): The following requirements apply to emissions of vinyl chloride to the atmosphere from the combination of all sources following the stripper(s) [or the reactor(s) if the plant has no stripper] in the plant process flow including, but not limited, to centrifuges, concentrators, blend tanks, filters, dryers, conveyor air discharges, baggers, storage containers, and inprocess wastewater.

(1) In polyvinyl chloride plants using stripping technology to control vinyl chloride emissions:

(i) For a grade or grades of polyvinyl chloride resin which have been produced by the plant on or before June 2, 1977, the weighted average residual vinyl chloride concentration in all the grades processed through the stripping operation on each calendar day, measured immediately after the stripping operation is completed, may not exceed the appropriate emission limit as follows:

(A) 2,000 ppm for polyvinyl chloride dispersion resins, excluding latex resins;

(B) 400 ppm for all other polyvinyl chloride resins, including latex resins, averaged separately for each type of resin;

(ii) For a grade or grades of polyvinyl chloride resin which have not been produced by the plant on or before June 2, 1977, the weighted average residual vinyl chloride concentration in all the grades processed through the stripping operation on each calendar day, measured immediately after the stripping operation is completed, may not exceed the appropriate emission limit as follows:

(A) 500 ppm for polyvinyl chloride dispersion resins, excluding latex resins;

(B) 100 ppm for all other polyvinyl chloride resins, including latex resins, averaged separately for each type of resin; or

(2) In polyvinyl chloride plants controlling vinyl chloride emissions with technology other than stripping or in addition to stripping:

(i) For sources being used to process a grade or grades of polyvinyl chloride

resin all of which had been produced by the plant on or before June 2, 1977:

(A) 2 g/kg (0.003 lb/lb) product from the stripper(s) [or reactor(s) if the plant has no stripper(s)] for dispersion polyvinyl chloride resins, excluding latex resins, with the product determined on a dry solids basis;

(B) 0.4 g/kg (0.004 lb/lb) product from the stripper(s) [or reactor(s) if the plant has no stripper(s)] for all other polyvinyl chloride resins, including latex resins, with the product determined on a dry solids basis.

(ii) For sources being used to process any grade of polyvinyl chloride resin not produced by the plant on or before June 2, 1977:

(A) 0.5 g/kg (0.0005 lb/lb) product from the stripper(s) [or reactor(s) if the plant has no stripper(s)] for dispersion polyvinyl chloride resins, excluding latex resins, with the product determined on a dry solids basis;

(B) 0.1 g/kg (0.0001 lb/lb) product from the strippers [or reactor(s) if the plant has no stripper(s)] for all other polyvinyl chloride resins, including latex resins, with the product determined on a dry solids basis.

(f) The requirements of paragraphs (b), (c), and (d) of this section do not apply to equipment that has been opened, is out of operation, and met the requirement in § 61.65(b)(6)(i) before being opened.

5. Section 61.65 is amended as follows:

A. By replacing the phrase "10 ppm" with the phrase "the appropriate emission limit specified in § 61.65(c)" in paragraphs (b)(1)(ii), (b)(2), (b)(3)(i), (b)(3)(ii), (b)(3)(iii), (b)(3)(iv), (b)(3)(v), (b)(5), (b)(6)(ii), and (b)(9)(ii);

B. By revising paragraph (c) and adding paragraph (d) as set forth below.

§ 61.65 Emission standard for ethylene dichloride, vinyl chloride, and polyvinyl chloride plants.

(c) The emission limit which is not to be exceeded is as follows: (1) Each source, for which construction had commenced on or before June 2, 1977, 10 ppm until (date three years after promulgation of these amendments) and 5 ppm after (date three years after promulgation of these amendments).

(2) Each source for which construction commenced after June 2, 1977, 5 ppm.

(d) The requirements in paragraphs (b)(1), (b)(2), (b)(5), (b)(6), (b)(7) and (b)(8) of this section are to be incorporated into a standard operating procedure, and made available upon request for inspection by the Administrator. The standard operating procedure is to include provisions for measuring the vinyl chloride in equipment  $\geq 4.75$  m<sup>3</sup> (1250 gal) in volume for which an emission limit is prescribed in § 61.65 (b)(6)(i) prior to opening the equipment and using Test Method 106, a portable hydrocarbon detector, or an equivalent or alternative method. The meth-

od of measurement is to meet the requirements in § 61.67(g)(5)(i)(A) or (g)(5)(i)(B).

6. In § 61.67, paragraph (a) is revised to read as follows:

§ 61.67 Emission tests.

(a) Unless a waiver of emission testing is obtained under § 61.13, the owner or operator of a source to which this subpart applies shall test emissions from the source as follows:

(1) For an existing source or a new source which has an initial startup date preceding October 21, 1976:

(i) Within 90 days following October 21, 1976, and

(ii) For those sources subject to §§ 61.62(a); 61.63(a); 61.64(a)(1), (b), (c), and (d); and/or 61.65(b)(1), (b)(2), (b)(3), (b)(5), (b)(6), and/or (b)(9), within 90 days following (date three years after the promulgation date of these amendments).

(2) For a new source for which initial startup occurs after October 21, 1976, within 90 days of startup.

7. In § 61.68, paragraph (c) is revised to read as follows:

§ 61.68 Emission monitoring.

(c) A daily span check is to be conducted for each vinyl chloride monitoring system used. For all of the sources listed in paragraph (a) of this section, except for the one for which an emission limit is prescribed in § 61.62(b)(1), the daily span check is to be conducted with a concentration of vinyl chloride equal to the concentration emission limit applicable to it. For a source subject to the emission limit prescribed in § 61.62(b)(1), the daily span check is to be conducted with a concentration of vinyl chloride which is determined to be equivalent to the emission limit for that source based on the emission test required by § 61.67. The calibration is to be done with either:

8. A new § 61.72 is added to read as follows:

§ 61.72 Request for interim emission limit.

(a) If in the opinion of the owner or operator of an existing source, that source will be unable to comply with the 5 ppm emission limit in §§ 61.62(a)(1); 61.63(a)(1); 61.64(a)(1)(i), (b)(1), (c)(1), (d)(1); and/or 61.65(c)(1) on or before (date three years after promulgation of these amendments), the owner or operator of that source may request that the Administrator approve an interim emission limit for that source. The request is to be in writing and is to be submitted to the Administrator within six months prior to (date two years after promulgation of these amendments). The request is to include:

(1) The reasons the source is incapable of being in compliance with the 5 ppm emission limit and data to support those reasons, and

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(2) A suggested interim emission limit and description of the methodology for attaining that limit.

(b) Any owner or operator of a source who has submitted to the Administrator a written request for an interim emission limit in accordance with § 61.72(a), shall within 60 days of the date of the written request meet with the Administrator concerning the information contained in the request. The meeting is to be open to interested persons, who are to be allowed to submit oral or written testimony relevant to compliance of the source.

(c) The Administrator will within 120 days of receipt of the written request required by paragraph (a) of this section, notify the owner or operator in writing of approval or denial of approval of an interim emission limit.

(d) If an interim emission limit is approved the notification is to include the level of the interim emission limit, which may be the level requested or a more stringent one.

(e) A determination to deny approval of an interim emission limit is to set forth the specific grounds on which such denial is based.

(f) Approval for any interim emission limit granted for any source under § 61.72(c) shall expire three years from the date of issuance. The owner or operator may request an extension of approval for an interim emission limit or a lower interim emission limit. The request is to be in writing, is to be submitted within six months prior to a year before the expiration date and is to include the information listed in § 61.72 (b), (c), (d), and (e) are to apply.

9. A new § 61.73 is added to read as follows:

### § 61.73 Offset of emissions due to new construction.

(a) No owner or operator is to construct a new source which alone or in combination with other sources being constructed at the same time results in an increased production rate unless he demonstrates to the Administrator's satisfaction that such construction will not cause an increase in vinyl chloride emissions within 8 km of any other source which is subject to this subpart.

(b) Reduction in production rate is an allowable mechanism for attaining an offset in emissions.

(c) The baseline emission rate is to be determined based on the level of emissions allowable by the standard.

(d) Reducing emissions from an interim emission limit to the standard for a source is not an acceptable means of achieving an emission offset.

(e) In the application for approval of construction required by § 61.07, owners or operators of sources subject to this subpart shall include, in addition to the information required by § 61.07, the following information:

(1) The name, address, and location of any plant subject to this subpart which is located within 8 km of the proposed location of the source to be constructed.

(f) The emission limits applicable to both the new source(s) and the source(s) at which emissions are being reduced to balance the increase in emissions due to the new construction are to be established by the Administrator in the approval for construction required by § 61.08.

(Secs. 112 and 301(a) of the Clean Air Act, sec. 4(a) of Pub. L. No. 91-604, 84 Stat. 1683; sec. 2 of Pub. L. No. 90-148, 81 Stat. 504 (42 U.S.C. 1855c-7, 1857g(a)). Secs. 61.67 and 61.68 also issued under sec. 114 of the Clean Air Act, sec. 4(a) of Pub. L. No. 91-604, 84 Stat. 1687 (42 U.S.C. 1857c-9).)

[FR Doc.77-15572 Filed 6-1-77;8:45 am]

FEDERAL REGISTER, VOL. 42, NO. 106-

—THURSDAY, JUNE 2, 1977

# SUMMARY TABLES OF MONITORING INFORMATION

| <u>Table #</u> | <u>Subject</u>                                              | <u>Regulation</u> |
|----------------|-------------------------------------------------------------|-------------------|
| 1              | NSPS Cource Categories Required to Continuously Monitor     | NSPS              |
| 2              | Operational Monitoring Requirements                         | NSPS              |
| 3              | Emission Limitations                                        | NSPS              |
| 4              | Proposal and Promulgation Dates for NSPS Source Categories  | NSPS              |
| 5              | NSPS Continuous Monitoring Requirements                     | NSPS              |
| 6              | Quarterly Reporting Requirements                            | NSPS              |
| 7              | Definitions of Excess Emissions                             | NSPS              |
| 8              | Spanning and Zeroing                                        | NSPS              |
| 9              | Span Specifications                                         | NSPS              |
| 10             | Notifications Requirements                                  | NSPS              |
| 11             | Specification Requirements                                  | NSPS              |
| 12             | Performance Specifications                                  | NSPS and S1P      |
| 13             | When to Run Monitor Performance Test                        | NSPS              |
| 14             | Requirements for S1P Revisions                              | S1P               |
| 15             | Existing Sources Required to Continuously Monitor Emissions | SIP               |
| 16             | NESHAP Monitoring Requirements for Vinyl Chloride Sources   | NESHAP            |

Table #1  
SOURCE CATEGORIES REQUIRED TO  
CONTINUOUSLY MONITOR

| SUBPART | SOURCE CATEGORY                | POLLUTANT                                                   | PROCESS                                                                                                 |
|---------|--------------------------------|-------------------------------------------------------------|---------------------------------------------------------------------------------------------------------|
| D       | Steam Generators               | Opacity                                                     | O <sub>2</sub> or CO <sub>2</sub>                                                                       |
|         | Solid Fossil Fuel              | SO <sub>2</sub><br>NO <sub>x</sub>                          |                                                                                                         |
|         | Liquid Fossil Fuel             | Opacity<br>SO <sub>2</sub> , NO <sub>x</sub>                | O <sub>2</sub> or CO <sub>2</sub>                                                                       |
|         | Gaseous Fossil Fuel            | NO <sub>x</sub>                                             | O <sub>2</sub> or CO <sub>2</sub>                                                                       |
| G       | Nitric Acid Plants             | SO <sub>2</sub>                                             |                                                                                                         |
| H       | Sulfuric Acid Plants           | SO <sub>2</sub>                                             |                                                                                                         |
| J       | Petroleum Refineries           | Opacity<br>CO<br>SO <sub>2</sub><br>H <sub>2</sub> S<br>TRS |                                                                                                         |
| N       | Iron and Steel Plants          |                                                             | Pressure loss<br>through venturi<br>scrubber<br>water supply<br>pressure                                |
| P       | Primary Copper Smelters        | Opacity<br>SO <sub>2</sub>                                  |                                                                                                         |
| Q       | Primary Zinc Smelters          | Opacity<br>SO <sub>2</sub>                                  |                                                                                                         |
| R       | Primary Lead Smelters          | Opacity<br>SO <sub>2</sub>                                  |                                                                                                         |
| TUVWX   | Phosphate Fertilizer<br>Plants |                                                             | Total pressure<br>drop across process<br>scrubbing systems                                              |
| Y       | Coal Preparations Plants       |                                                             | exit gas temp.<br>pressure loss<br>through venturi<br>water supply<br>pressure to control<br>equipment. |

Table #1, continued

| SUBPART | SOURCE CATEGORY                        | POLLUTANT            | PROCESS                                                                                                                         |
|---------|----------------------------------------|----------------------|---------------------------------------------------------------------------------------------------------------------------------|
| Z       | Ferroalloy production facilities       | Opacity              | flowrate through hood.<br>furnace power input                                                                                   |
| AA      | Steel Plants:<br>Electric Arc Furnaces | Opacity              | Volumetric flow rate through each each separately ducted hood.<br>pressure in the free space inside the electric arc furnace.   |
| BB      | Kraft Pulp Mills                       | Opacity<br>TRS       | O <sub>2</sub><br>Temperature<br>Pressure loss of the gas stream through the control equipment scrubbing liquid supply pressure |
| HH      | Lime Manufacturing Plants              |                      |                                                                                                                                 |
|         | Rotary Lime Kilns                      | Opacity <sup>a</sup> | pressure loss of steam through the scrubber<br><br>scrubbing liquid supply pressure                                             |
|         | Lime Hydrator                          |                      | scrubbing liquid flow rate<br><br>measurement of the electric current (amperes) used by the scrubber                            |

a Does not apply when there is a wet scrubbing emission control device.

Table # 2  
OPERATIONAL MONITORING REQUIREMENTS (NSPS)  
(Non-continuous)

| Subpart                                  | Requirement                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              |
|------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| E. Incinerators                          | Daily charging rates and hours of operation.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |
| F. Portland Cement Plants                | Daily production rates and kiln feed rates.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              |
| G. Nitric Acid Plants                    | Daily production rate and hours of operation.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |
| H. Sulfuric Acid Plants                  | The conversion factor shall be determined, as a minimum, three times daily by measuring the concentration of sulfur dioxide entering the converter.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                      |
| J. Petroleum Refineries                  | Record daily the average coke burn-off rate and hours of operation for any fluid catalytic cracking unit catalyst regenerator subject to the particulate or carbon monoxide standard.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |
| K. Storage Vessels for Petroleum Liquids | Maintain a file of each type of petroleum liquid stored and the dates of storage. Show when storage vessel is empty. Determine and record the average monthly storage temperature and true vapor pressure of the petroleum liquid stored if :<br>(1) the petroleum liquid, as stored, has a vapor pressure greater than 26 mm Hg but less than 78 mm and is stored in a storage vessel other than one equipped with a floating roof, a vapor recovery system or their equivalents; or<br>(2) the petroleum liquid has a true vapor pressure, as stored, greater than 470 mm Hg and is stored in a storage vessel other than one equipped with a vapor recovery system or its equivalent. |

| Subpart                                                              | Requirement                                                                                                                                                                            |
|----------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| O. Sewage Treatment Plants                                           | 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.                       |
| P. Primary Copper Smelter                                            | 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.                                    |
| S. Primary Aluminum Reduction Plants                                 | Determine daily, the weight of aluminum and anode produced. Maintain a record of daily production rates of aluminum and anodes, raw material feed rates, and cell or potline voltages. |
| T. Phosphate Fertilizer Industry: Wet-Process Phosphoric Acid Plants | Determine the mass flow of phosphorus-bearing feed material to the process. Maintain a daily record of equivalent $P_2O_5$ feed.                                                       |
| U. Phosphate Fertilizer Industry: Superphosphoric Acid Plants        | Determine the mass flow of phosphorus-bearing feed material to the process. Record daily the equivalent $P_2O_5$ feed.                                                                 |
| V. Phosphate Fertilizer Industry: Diammonium Phosphate Plants        | Determine the mass flow of phosphorus-bearing feed material to the process. Maintain a daily record of equivalent $P_2O_5$ feed.                                                       |
| W. Phosphate Fertilizer Industry: Triple Superphosphate Plants       | Determine the mass flow of phosphorus-bearing feed material to the process. Maintain a daily record of equivalent $P_2O_5$ feed.                                                       |
| X. Phosphate Fertilizer Industry                                     | Maintain an accurate account of triple superphosphate in storage. Maintain a daily record of total equivalent $P_2O_5$ stored.                                                         |

| Subpart                                    | Requirement                                                                                                                                                                                                                                                                                                                                                            |
|--------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Z. Ferroalloy Production Facilities        | Maintain daily records of (1) the product; (2) description of constituents of furnace charge, including the quantity, by weight; (3) the time and duration of each tapping period and the identification of material tapped (slag or product); (4) all furnace power input data; and (5) all flow rate data or all fan motor power consumption and pressure drop data. |
| AA. Steel Plants:<br>Electric Arc Furnaces | Maintain daily records of (1) the time and duration of each charge; (2) the time and duration of each tap; (3) all flow rate data, and (4) all pressure data.                                                                                                                                                                                                          |

Table # 3  
EMISSION LIMITATIONS (NSPS)

| <u>SUBPART</u>                          | <u>POLLUTANT</u> | <u>EMISSION LEVELS</u>                        |
|-----------------------------------------|------------------|-----------------------------------------------|
| D Fossil Fuel-Fired<br>Steam Generators |                  |                                               |
| Liquid fossil<br>fuel                   | Particulate      | 43 ng/joule<br>(0.10 lb/10 <sup>6</sup> BTU)  |
|                                         | Opacity          | 20%, 40% 2 min/hr                             |
|                                         | SO <sub>2</sub>  | 340 ng/joule<br>(0.80 lb/10 <sup>6</sup> BTU) |
|                                         | NO <sub>x</sub>  | 130 ng/joule<br>(0.30 lb/10 <sup>6</sup> BTU) |
| Solid fossil<br>fuel                    | Particulate      | 43 ng/joule<br>(0.10 lb/10 <sup>6</sup> BTU)  |
|                                         | Opacity          | 20%, 40% 2 min/hr                             |
|                                         | SO <sub>2</sub>  | 520 ng/joule<br>(1.2 lb/10 <sup>6</sup> BTU)  |
|                                         | NO <sub>x</sub>  | 300 ng/joule<br>(0.70 lb/10 <sup>6</sup> BTU) |
| Gaseous fossil<br>fuel                  | Particulate      | 43 ng/joule<br>(0.10 lb/10 <sup>6</sup> BTU)  |
|                                         | Opacity          | 20%, 40% 2 min/hr                             |
|                                         | NO <sub>x</sub>  | 86 ng/joule<br>(0.20 lb/10 <sup>6</sup> BTU)  |
| Mixture of<br>fossil fuel               | Particulate      | 43 ng/joule<br>(0.10 lb/10 <sup>6</sup> BTU)  |
|                                         | Opacity          | 20%, 40% 2 min/hr                             |
|                                         | SO <sub>2</sub>  | $\frac{y(340) + z(520)}{y + z} *$             |
|                                         | NO <sub>x</sub>  | $\frac{x(86) + y(130) + z(300)}{x + y + z}$   |
|                                         |                  |                                               |

\*x = percentage of total heat input from gaseous fossil fuel  
y = percentage of total heat input from liquid fossil fuel  
z = percentage of total heat input from solid fossil fuel

Table #3, continued

| <u>SUBPART</u>                   | <u>POLLUTANT</u>                    | <u>EMISSION LEVELS</u>                                                     |
|----------------------------------|-------------------------------------|----------------------------------------------------------------------------|
| E Incinerators                   | Particulate                         | 0.18 g/dscm<br>(0.08 gr/dscf)<br>(corrected to 12% CO <sub>2</sub> )       |
| F Portland Cement<br>Plants      |                                     |                                                                            |
| Kiln                             | Particulate                         | 0.15 kg/metric ton<br>(0.30 lb/ton)                                        |
|                                  | Opacity                             | 10%                                                                        |
| Clinker cooler                   | Particulate                         | 0.05 kg/metric ton<br>of feed<br>(0.10 lb/ton)                             |
|                                  | Opacity                             | 20%                                                                        |
| Other emission<br>points         | Opacity                             | 10%                                                                        |
| G Nitric Acid Plants             | NO <sub>2</sub>                     | 1.5 kg/metric tons<br>of acid produced<br>(3.0 lb/ton of acid<br>produced) |
|                                  | Opacity                             | 10%                                                                        |
| H Sulfuric Acid<br>Plants        | SO <sub>2</sub>                     | 2 kg/metric tons<br>of acid produced<br>(4.0 lb/ton of<br>acid produced)   |
|                                  | H <sub>2</sub> SO <sub>4</sub> mist | 0.075 kg/metric tons<br>of acid produced<br>(0.15 lb/ton)                  |
| I Asphalt Concrete<br>Plants     | Particulate                         | 90 mg/dscm<br>(0.04 gr/dscf)                                               |
|                                  | Opacity                             | 20%                                                                        |
| J Petroleum<br>Refineries        |                                     |                                                                            |
| fluid catalytic<br>cracking unit | Particulate                         | 1.0 kg/1000 of<br>coke burn-off                                            |
|                                  | Opacity                             | 30%                                                                        |
|                                  | CO                                  | 0.050%                                                                     |

Table #3, continued

| <u>SUBPART</u>                          | <u>POLLUTANT</u> | <u>EMISSION LEVELS</u>                                                                                                                                                                                                                                     |
|-----------------------------------------|------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Claus sulfur recovery plant             | SO <sub>2</sub>  | 0.025%                                                                                                                                                                                                                                                     |
|                                         | Trs              | 0.030%                                                                                                                                                                                                                                                     |
|                                         | H <sub>2</sub> S | 0.0010%                                                                                                                                                                                                                                                    |
| K Storage Vessels for Petroleum Liquids | Hydrocarbons     | If vapor pressure is 78-570 mm Hg the storage vessel shall be equipped with a floating roof or a vapor recovery system or thin equivalents. If vapor pressure is greater than 570 mm Hg, the storage vessel shall be equipped with a vapor recovery system |
| L Secondary Lead Smelters               |                  |                                                                                                                                                                                                                                                            |
| Reverberatory and blast furnaces        | Particulate      | 50 mg/dscm (0.022 gr/dscf)                                                                                                                                                                                                                                 |
|                                         | Opacity          | 20%                                                                                                                                                                                                                                                        |
| Pot furnaces                            | Opacity          | 10%                                                                                                                                                                                                                                                        |
| M Secondary Brass and Bronze Plants     |                  |                                                                                                                                                                                                                                                            |
| Reverberatory furnaces                  | Particulate      | 50 mg/dscm (0.022 gr/dscf)                                                                                                                                                                                                                                 |
|                                         | Opacity          | 20%                                                                                                                                                                                                                                                        |
| Blast and electric furnaces             | Opacity          | 10%                                                                                                                                                                                                                                                        |
| N Iron and Steel Plants                 | Particulate      | 50 mg/dscm                                                                                                                                                                                                                                                 |
| (BOPF)                                  | Opacity          | 10%<br>>10% but <20% may occur once per steel production cycle                                                                                                                                                                                             |
| O Sewage Treatment Plants               | Particulate      | 0.65 g/kg dry sludge input (1.30 lb/ton)                                                                                                                                                                                                                   |
|                                         | Opacity          | 20%                                                                                                                                                                                                                                                        |
| P Primary Copper Smelters               |                  |                                                                                                                                                                                                                                                            |
| Dryer                                   | Particulate      | 50 mg/dscm (0.022 gr/dscf)                                                                                                                                                                                                                                 |

Table # 3, continued

| <u>SUBPART</u>                                                  | <u>POLLUTANT</u> | <u>EMISSION LEVELS</u>                            |
|-----------------------------------------------------------------|------------------|---------------------------------------------------|
|                                                                 | Opacity          | 20%                                               |
| Roaster, smelting furnace, copper converter                     | SO <sub>2</sub>  | 0.065%                                            |
|                                                                 | Opacity          | 20%                                               |
| Q Primary Zinc Smelters                                         |                  |                                                   |
| Sintering machine                                               | Particulate      | 50 mg/dscm<br>(0.022 gr/dscf)                     |
|                                                                 | Opacity          | 20%                                               |
| Roaster                                                         | SO <sub>2</sub>  | 0.065%                                            |
|                                                                 | Opacity          | 20%                                               |
| R Primary Lead Smelters                                         |                  |                                                   |
| Blast or reverberatory furnace, sintering machine discharge end | Particulate      | 50 mg/dscm<br>(0.022 gr/dscf)                     |
|                                                                 | Opacity          | 20%                                               |
| Sintering machine, electric smelting furnace, converter         | SO <sub>2</sub>  | 0.065%                                            |
|                                                                 | Opacity          | 20%                                               |
| S Primary Aluminum Reduction Plants                             |                  |                                                   |
| Soderberg plants                                                | Total fluorides  | 1 kg/metric ton of Al produced<br>(2 lb/ton)      |
|                                                                 | Opacity          | 10%                                               |
| Prebake plants                                                  | Total fluorides  | 0.95 kg/metric ton of Al produced<br>(1.9 lb/ton) |
|                                                                 | Opacity          | 10%                                               |
| Anode bake plants                                               | Total fluorides  | 0.05 kg/metric ton of Al produced                 |
|                                                                 | Opacity          | 20%                                               |

Table # 3, continued

| <u>SUBPART</u>                                                                                       | <u>POLLUTANT</u>   | <u>EMISSION LEVELS</u>                                                                        |
|------------------------------------------------------------------------------------------------------|--------------------|-----------------------------------------------------------------------------------------------|
| T Phosphate Fertilizer Industry:<br>Wet Process<br>Phosphoric Acid<br>Plants                         | Total<br>fluorides | 10 g/metric ton of<br>$P_2O_5$ feed<br>(0.020 lb/ton)                                         |
| U Phosphate Fertilizer Industry:<br>Super-phosphoric<br>Acid Plants                                  | Total<br>fluorides | 5 g/metric ton of<br>$P_2O_5$ feed<br>(0.020 lb/ton)                                          |
| V Phosphate Fertilizer Industry:<br>Diammonium Phosphate                                             | Total<br>fluorides | 30 g/metric ton of<br>$P_2O_5$ feed<br>(0.060 lb/ton)                                         |
| W Phosphate Fertilizer Industry:<br>Triple Super-<br>Phosphate                                       | Total<br>fluorides | 100 g/metric ton of<br>equivalent $P_2O_5$ feed<br>(0.20 lb/ton)                              |
| X Phosphate Fertilizer Industry:<br>Granular Triple<br>Superphosphate                                | Total<br>fluorides | 0.25 g/hr/metric ton<br>of equivalent $P_2O_5$<br>stored<br>( $5.0 \times 10^{-4}$ lb/hr/ton) |
| Y Coal Preparation<br>Plants                                                                         |                    |                                                                                               |
| Thermal dryer                                                                                        | Particulate        | 0.070 g/dscm<br>(0.031 gr/dscf)                                                               |
|                                                                                                      | Opacity            | 20%                                                                                           |
| Pneumatic<br>coal cleaving<br>equipment                                                              | Particulate        | 0.040 g/dscm<br>(0.031 gr/dscf)                                                               |
|                                                                                                      | Opacity            | 10%                                                                                           |
| Processing and<br>conveying equip-<br>ment, storage<br>systems, trans-<br>fer and loading<br>systems | Opacity            | 20%                                                                                           |

Table # 3, continued

| <u>SUBPART</u>                     | <u>POLLUTANT</u> | <u>EMISSION LEVELS</u>                                                                                                         |
|------------------------------------|------------------|--------------------------------------------------------------------------------------------------------------------------------|
| Z Ferroalloy Production Facilities |                  |                                                                                                                                |
| Electric submerged arc furnaces    | Particulate      | 0.45 kg/MW-hr<br>(0.99 lb/MW-hr)<br>(high silicon alloys)<br>0.23 kg/MW-hr<br>(0.51 lb/MW-hr)<br>(chrome and manganese alloys) |
|                                    | Opacity          | 15%                                                                                                                            |
|                                    | CO               | 20%                                                                                                                            |
| Dust handling equipment            | Opacity          | 10%                                                                                                                            |
| AA Steel Plants                    |                  |                                                                                                                                |
| Electric arc furnaces              | Particulate      | 12 mg/dscm<br>(0.0052 gr/dscf)                                                                                                 |
| Control device                     | Opacity          | 3%                                                                                                                             |
| Shop roof                          | Opacity          | 0, except:<br>20% - charging<br>40% - tapping                                                                                  |
| Dust handling equipment            | Opacity          | 10%                                                                                                                            |
| BB Kraft Pulp Mills                |                  |                                                                                                                                |
| Recovery Furnace                   | Particulate      | 0.10 g/dscm                                                                                                                    |
|                                    | Opacity          | 35%                                                                                                                            |
| Straight recovery furnace          | TRS              | 5 ppm                                                                                                                          |
| Cross recovery furnace             | TRS              | 25 ppm                                                                                                                         |

Table #3, continued

| <u>SUBPART</u>                                                                                                                       | <u>POLLUTANT</u> | <u>EMISSION LEVELS</u>             |
|--------------------------------------------------------------------------------------------------------------------------------------|------------------|------------------------------------|
| Smelt dissolving tank                                                                                                                | Particulate      | 0.1g/kg black liquor (dry out)     |
|                                                                                                                                      | TRS              | 0.0084g/kg black liquor (dry out)  |
| Lime kiln                                                                                                                            | TRS              | 8 ppm                              |
| gaseous fuel                                                                                                                         | Particulate      | 0.15g/dscm                         |
| liquid fuel                                                                                                                          | Particulate      | 0.30g/dscm                         |
| Digester system, brown stock washer system, multiple-effect evaporation system, black liquor oxidation system or condensate stripper | TRS              | 5 ppm                              |
| HH Lime Manufacturing Plants                                                                                                         |                  |                                    |
| Rotary Lime kiln                                                                                                                     | Particulate      | 0.15 kg/megagram of limestone feed |
|                                                                                                                                      | Opacity          | 10%                                |
| Lime Hydrator                                                                                                                        | Particulate      | 0.075 kg/megagram of lime feed     |

Table # 4

## PROPOSAL AND PROMULGATION DATES FOR NSPS SOURCE CATEGORIES

| Subpart | Source                                | Promulgation Date | Proposed Date |
|---------|---------------------------------------|-------------------|---------------|
| D       | Fossil Fuel Fired Steam Generators    | 12/23/71          | 8/17/71       |
| E       | Incinerators                          | 12/23/71          | 8/17/71       |
| F       | Portland Cement Plants                | 12/23/71          | 8/17/71       |
| G       | Nitric Acid Plants                    | 12/23/71          | 8/17/71       |
| H       | Sulfuric Acid Plants                  | 12/23/71          | 8/17/71       |
| I       | Asphalt Concrete Plants               | 3/8/74            | 6/11/73       |
| J       | Petroleum Refineries                  | 3/8/74            | 6/11/73       |
| K       | Storage Vessels for Petroleum Liquids | 3/8/74            | 6/11/73       |
| L       | Secondary Lead Smelters               | 3/8/74            | 6/11/73       |
| M       | Brass and Bronze Production Plants    | 3/8/74            | 6/11/73       |
| N       | Iron and Steel Plants                 | 3/8/74            | 6/11/73       |
| O       | Sewage Treatment Plants               | 3/8/74            | 6/11/73       |
| P       | Primary Copper Smelter                | 1/15/76           | 10/16/74      |
| Q       | Primary Zinc Smelter                  | 1/15/76           | 10/16/74      |
| R       | Primary Lead Smelter                  | 1/15/76           | 10/16/74      |
| S       | Primary Aluminum Reduction Plants     | 1/26/76           | 10/23/74      |
| TUVWX   | Phosphate Fertilizer Industry         | 8/6/75            | 10/22/74      |
|         | Coal Preparation Plants               | 1/15/76           | 10/24/74      |
| Z       | Ferroalloy Production Facilities      | 5/4/76            | 10/21/74      |
| AA      | Steel Plants: Electric Arc Furnaces   | 9/23/75           | 10/21/74      |
| BB      | Kraft Pulp Mills                      | 2/23/78           | 9/24/76       |
| HH      | Lime Manufacturing                    | 3/7/78            | 3/3/77        |

Table #5  
CONTINUOUS MONITORING REQUIREMENTS

- I. Installed and operational prior to conducting performance tests<sup>1</sup>
- II. Conduct monitoring system performance evaluations during performance tests or 30 days thereafter (for specification requirements, see Table #11)
- III. Check zero and span drift at least daily (see Table #8)
- IV. Time for cycle of operations (sampling, analyzing, and data recording)
  - A. Opacity - 10 seconds
  - B. Gas Monitors - 15 minutes
- V. Installed to provide representative sampling
- VI. Reduction of data
  - A. Opacity - 6-minute average
  - B. Gaseous Pollutants - hourly average
- VII. Source must notify agency, more than 30 days prior, of date upon which demonstration of continuous monitoring system performance is to commence.

<sup>1</sup>Performance tests shall be conducted 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.

Table #6  
QUARTERLY REPORTING REQUIREMENTS<sup>1</sup> (NSPS)

- I. Excess Emissions
  - A. Description of Excess Emission
    - 1. Magnitude
    - 2. Conversion factors used
    - 3. Date and time of commencement and completion
  - B. Explanation of Excess Emission
    - 1. Occurrences during startups, shutdowns, and malfunctions
    - 2. Nature and cause of malfunction
    - 3. Corrective and preventative action taken
  - C. To be Submitted in Units Same as Standard
- II. Continuous Monitoring Systems
  - A. Date and Time when System was Inoperative (except for zero and span checks)
  - B. Nature of System Repairs or Adjustments
- III. Lack of Occurrences During A Quarter
  - A. Absence of Excess Emissions during Quarter
  - B. Absence of Adjustments, Repairs, or Inoperativeness of Continuous Monitoring System

<sup>1</sup> "Each owner or operator required to install a continuous monitoring system shall submit a written report ... for every calendar quarter"

"All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter..."

Table #7

## DEFINITION OF EXCESS EMISSIONS (NSPS)

| SUBPART | POLLUTANT       | EXCESS EMISSION                                                                                                                                                                       |
|---------|-----------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| D       | opacity         | any six-minute period during which the average opacity of emissions exceeds 20% opacity, except that one six-minute average per hour of up to 27% opacity need not be reported.       |
|         | SO <sub>2</sub> | any three-hour period during which the average emissions of SO <sub>2</sub> (arithmetic average of three contiguous one-hour periods) exceed the standard                             |
|         | NO <sub>x</sub> | any three-hour period during which the average emissions of NO <sub>x</sub> (arithmetic average of three contiguous one-hour periods) exceed the standard                             |
| G       | NO <sub>x</sub> | any three-hour period during which the average nitrogen oxides emissions (arithmetic average of three contiguous one-hour periods) exceed the standard                                |
| H       | SO <sub>2</sub> | 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 |
| J       | Opacity         | All one-hour periods which contain two or more six-minute periods during which the average opacity exceeds 30 percent.                                                                |
|         | CO              | All hourly periods during which the average CO concentration exceeds the standard.                                                                                                    |
|         | SO <sub>2</sub> | Any three hour period during which the average concentration of SO <sub>2</sub> emissions from any fuel gas combustion device exceeds the standard.                                   |
|         | SO <sub>2</sub> | Any twelve-hour period during which the average concentration of SO <sub>2</sub> emissions from any Claus sulfur recovery plant exceed the standard.                                  |

Table #7, continued

| SUBPART                                                                                                                                                           | POLLUTANT       | EXCESS EMISSION                                                                                                                                    |
|-------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------|----------------------------------------------------------------------------------------------------------------------------------------------------|
| P                                                                                                                                                                 | Opacity         | any six-minute period during which the average opacity exceeds the standard                                                                        |
|                                                                                                                                                                   | SO <sub>2</sub> | any six-hour period during which the average emissions of SO <sub>2</sub> (arithmetic mean of six contiguous one-hour periods) exceed the standard |
| Q                                                                                                                                                                 | Opacity         | any six minute period during which the average opacity exceeds the standard                                                                        |
|                                                                                                                                                                   | SO <sub>2</sub> | any two hour period during which the average emissions of SO <sub>2</sub> (arithmetic mean of two contiguous one-hour periods) exceed the standard |
| R                                                                                                                                                                 | Opacity         | any six minute period during which the average opacity exceeds the standard                                                                        |
|                                                                                                                                                                   | SO <sub>2</sub> | any two hour period during which the average emissions of SO <sub>2</sub> (arithmetic mean of two contiguous one hour periods) exceed the standard |
| Z                                                                                                                                                                 | Opacity         | all six minute periods in which the average opacity is 15 percent or greater                                                                       |
| AA                                                                                                                                                                | Opacity         | all six minute periods during which the average opacity is 3 percent or greater                                                                    |
| BB<br>Recovery<br>furnace                                                                                                                                         | TRS             | Any twelve hour period during which the TRS emissions exceed the standard.                                                                         |
|                                                                                                                                                                   | Opacity         | Any six minute period during which the average opacity exceeds the standard.                                                                       |
| Lime kiln                                                                                                                                                         | TRS             | Any twelve hour period during which the TRS emissions exceed the standard.                                                                         |
| Digester<br>system, brown<br>stock washer<br>system, multiple-<br>effect evaporator<br>system, black<br>liquor oxidation<br>system, or<br>condensate<br>stripper. | TRS             | Any twelve hour period during which the TRS emissions exceed the standard.                                                                         |
| HH                                                                                                                                                                | Opacity         | All six minute periods during which the average opacity is greater than the standard.                                                              |

Table #8  
SPANNING AND ZEROING

- I. Explanation of Zero and Span Checks
  - A. Extractive gas monitors
    - 1. Span gas composition
      - a. SO<sub>2</sub> - sulfur dioxide/nitrogen or gas mixture
      - b. NO - nitric oxide/oxygen-free nitrogen mixture
      - c. NO<sub>2</sub> - nitrogen dioxide/air mixture
    - 2. Zero gases
      - a. Ambient air
      - or b. A gas certified by the manufacturer to contain less than 1 ppm of the pollutant gas
    - 3. Analysis of span and zero gases
      - a. Span and zero gases certified by their manufacturer to be traceable to National Bureau of Standards reference gases shall be used whenever these gases are available
      - b. Span and zero gases should be reanalyzed every six months after date of manufacture with Reference Method 6 for SO<sub>2</sub> and 7 for NO<sub>x</sub>
      - c. Span and zero gases shall be analyzed two weeks prior to performance specification tests
  - B. Non-extractive gas monitors
    - 1. Span check - certified gas cell or test cell
    - 2. Zero check - mechanically produced or calculated from upscale measurements
  - C. Transmissometers
    - 1. Span check is a neutral density filter that is certified within + 3 percent opacity
    - 2. Zero check is a simulated zero
  - D. Span values are specified in each subpart
    - 1. Span check is 90% of span.
- II. Adjustment of Span and Zero
  - A. Adjust the zero and span whenever the zero or calibration drift exceeds the limits of applicable performance specification in Appendix B.
    - 1. For opacity, clean optical surfaces before adjusting zero or span drift
    - 2. For opacity systems using automatic zero adjustments, the optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds four percent opacity
- III. How to Span and Zero
  - A. Extractive gas monitors
    - 1. Introduce the zero and span gas into the monitoring system as near the probe as practical
  - B. Non-extractive gas monitors
    - 1. Use a certified gas cell or test cell to check span
    - 2. The zero check is performed by computing the zero value from upscale measurements or by mechanically producing a zero
  - C. Transmissometers
    - 1. Span check with a neutral density filter
    - 2. Zero check by simulating a zero opacity

Table # 9  
SPAN SPECIFICATIONS

| <u>SUBPART</u>                              | <u>POLLUTANT</u> | <u>SPAN</u>             |
|---------------------------------------------|------------------|-------------------------|
| D Fossil Fuel Fired<br>Steam Generators     |                  |                         |
| liquid fossil fuel                          | opacity          | 80, 90, or 100% opacity |
|                                             | SO <sub>2</sub>  | 1000 ppm                |
|                                             | NO <sub>x</sub>  | 500 ppm                 |
| solid fossil fuel                           | opacity          | 80, 90, or 100% opacity |
|                                             | SO <sub>2</sub>  | 1500 ppm                |
|                                             | NO <sub>x</sub>  | 1000                    |
| gaseous fuel                                | NO <sub>x</sub>  | 500 ppm                 |
| mixtures of fossil fuels                    | opacity          | 80,90, or 100% opacity  |
|                                             | SO <sub>2</sub>  | 1000y + 1500z l         |
|                                             | NO <sub>x</sub>  | 500 (x+y) + 1000z       |
| G Nitric Acid Plants                        | NO <sub>2</sub>  | 500 ppm                 |
| H Sulfuric Acid Plants                      | SO <sub>2</sub>  | 1000 ppm                |
| J Petroleum Refineries<br>Catalytic Cracker | Opacity          | 60,70, or 80% Opacity   |
|                                             | CO               | 1000 ppm                |
| Claus Recovery Plant                        | SO <sub>2</sub>  | 500 ppm                 |
|                                             | H <sub>2</sub> S | 20 ppm                  |
|                                             | TRS              | 600 ppm                 |
| Fuel Gas Combustion                         | SO <sub>2</sub>  | 100 ppm                 |
|                                             | H <sub>2</sub> S | 300 ppm                 |
| P Primary Copper Smelters                   | Opacity          | 80 to 100% opacity      |
|                                             | SO <sub>2</sub>  | 0.20% by volume         |
| Q Primary Zinc Smelters                     | Opacity          | 80 to 100% opacity      |
|                                             |                  | 0.20% by volume         |
| R Primary Lead Smelters                     | Opacity          | 80 to 100% opacity      |
|                                             | SO <sub>2</sub>  | 0.20% by volume         |
| Z Ferroalloy Production<br>Facilities       | Opacity          | not specified           |
| AA Steel Plants                             | Opacity          | not specified           |

Table #9, continued

| <u>SUBPART</u>                                                                                                                      | <u>POLLUTANT</u> | <u>SPAN</u>                                                                               |
|-------------------------------------------------------------------------------------------------------------------------------------|------------------|-------------------------------------------------------------------------------------------|
| BB Kraft Pulp Mills<br>Recovery Furnace                                                                                             | Opacity          | 70% opacity                                                                               |
| Lime kiln, recovery furnace<br>digester system, brown                                                                               | O <sub>2</sub>   | 20%                                                                                       |
| Stock washer system,<br>multiple effect<br>evaporator system,<br>black liquor oxidation<br>system, or condensate<br>stripper system | TRS              | 30 ppm<br>(except that for<br>any cross recovery<br>furnace the span shall<br>be 500 ppm) |
| HH Lime Manufacturing Plant                                                                                                         | Opacity          | 40% Opacity                                                                               |

1

x= fraction of total heat input from gas

y= fraction of total heat input from liquid fossil fuel

z= fraction of total heat input from solid fossil fuel

Span value shall be rounded off to the nearest 500 ppm

Table #10  
NOTIFICATION REQUIREMENTS <sup>1</sup>

| <u>Requirements</u>                                                                                                                        | <u>Time Deadline</u>                                                      |
|--------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------|
| I. Date of Commencement of Construction                                                                                                    | Less than 30 days after such date                                         |
| II. Anticipated Date of Initial Startup                                                                                                    | Less than 60 or more than 30 days prior to date                           |
| III. Actual Date of Initial Startup                                                                                                        | Within 15 days after date                                                 |
| IV. Any physical or operational change to a facility which may increase the emission rate of any air pollutant to which a standard applies | Postmarked 60 days or as soon as practical before the change is commenced |
| A. The precise nature of the change                                                                                                        |                                                                           |
| B. Present and proposed emission control systems                                                                                           |                                                                           |
| C. Productive capacity before and after the change                                                                                         |                                                                           |
| D. Expected completion date of change                                                                                                      |                                                                           |
| V. Date upon which demonstration of continuous monitoring system performance commences                                                     | more than 30 days prior                                                   |

<sup>1</sup>

"Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification..."

Table #11  
SPECIFICATION REQUIREMENTS (NSPS)

|         | Sept. 11, 1974 |       | October 6, 1975 |       | Specification Requirements                 |
|---------|----------------|-------|-----------------|-------|--------------------------------------------|
|         | Before         | After | Before          | After |                                            |
| CASE 1* | PI             |       |                 |       | None-unless requested by the administrator |
| CASE 2* | P              | I     |                 |       | None-unless requested by the administrator |
| CASE 3* | P              |       |                 | I     | Accuracy                                   |
| CASE 4  |                | PI    |                 |       | All requirements in Appendix B             |
| CASE 5  |                | P     |                 | I     | All requirements in Appendix B             |
| CASE 6  |                |       |                 | PI    | All requirements in Appendix B             |

P - Purchased

I - Installed

\* Cases 1,2, and 3 shall be upgraded or replaced with new continuous monitoring systems and shall comply with Specification Requirements in Appendix B by September 11, 1979

Table # 12

## PERFORMANCE SPECIFICATIONS

TRANSMISSOMETERS

|                         |                      |
|-------------------------|----------------------|
| Calibration error       | $\leq 3$ pct opacity |
| Zero drift (24h)        | $\leq 2$ pct opacity |
| Calibration drift (24h) | $\leq 2$ pct opacity |
| Response time           | 10 s maximum         |
| Operational test period | 168 hours            |

NO<sub>x</sub> and SO<sub>2</sub>

|                         |                                                                      |
|-------------------------|----------------------------------------------------------------------|
| Accuracy                | $\leq 20$ pct of the mean value<br>of the reference method test data |
| Calibration error       | $\leq 5$ pct of (50 pct, 90 pct)<br>calibration gas mixture value    |
| Zero drift (2h)         | 2 pct of span                                                        |
| Zero drift (24h)        | 2 pct of span                                                        |
| Calibration drift (2h)  | 2 pct of span                                                        |
| Calibration drift (24h) | 2.5 pct of span                                                      |
| Response time           | 15 min maximum                                                       |
| Operational period      | 168 h minimum                                                        |

O<sub>2</sub> and CO<sub>2</sub>

|                        |                                                  |
|------------------------|--------------------------------------------------|
| Zero drift (2h)        | $\leq 0.4$ pct O <sub>2</sub> or CO <sub>2</sub> |
| Zero drift (24h)       | $\leq 0.5$ pct O <sub>2</sub> or CO <sub>2</sub> |
| Calibration drift (2h) | $\leq 0.4$ pct O <sub>2</sub> or CO <sub>2</sub> |
| Operational period     | 168 H minimum                                    |
| Response time          | 10 min                                           |

TABLE #13

WHEN TO RUN THE MONITOR PERFORMANCE TEST

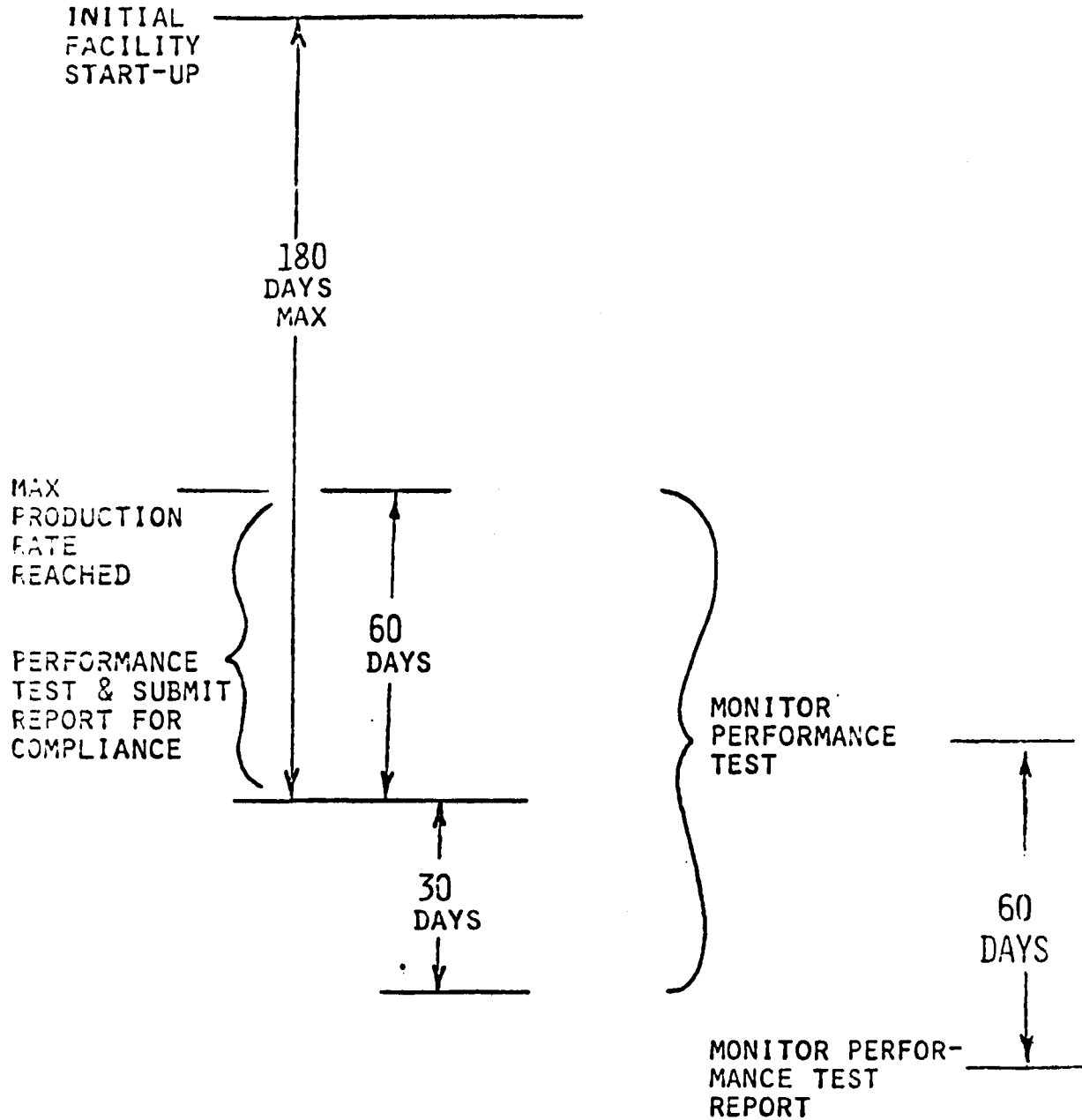


Table #14

REQUIREMENTS FOR SIP REVISIONS

- I. Submit SIP Revisions by October 6, 1976
- II. Contain monitoring requirements for the following sources (as a minimum)
  - A. Fossil Fuel-Fired Steam Generators
  - B. Sulfuric Acid Plants
  - C. Nitric Acid Plants
  - D. Petroleum Refineries  
(see Table #15)
- III. Require that sources evaluate the performance of their monitoring system
- IV. Require the sources to maintain a file of all pertinent continuous monitoring data
  - A. Emission measurements
  - B. Monitoring system evaluation data
  - C. Adjustments and maintenance performed on the monitoring system
- V. Require the source to submit periodic (such period not to exceed 3 months) reports containing the following information.
  - A. Number and magnitude of excess emissions
  - B. Nature and cause of excess emissions
  - C. Statement concerning absence of excess emissions and/or monitor inoperativeness
- VI. Require that monitoring begin within 18 months of EPA approval of the SIP revision (or within 18 months of EPA promulgation)

TABLE #15

## EXISTING SOURCES REQUIRED TO CONTINUOUSLY MONITOR EMISSIONS

| <u>Source</u>                         | <u>Pollutant</u> | <u>Comments</u>                                                                                                                                                                                                                                                                       |
|---------------------------------------|------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Fossil Fuel-Fired<br>Steam Generators | SO <sub>2</sub>  | 1. >250 x 10 <sup>6</sup> Btu/hr<br>2. Source that has control equipment for SO <sub>2</sub>                                                                                                                                                                                          |
|                                       | NO <sub>x</sub>  | 1. >1000 x 10 <sup>6</sup> Btu/hr<br>2. Located in a designated non-attainment area for NO <sub>2</sub> .<br>3. Exempt if source is 30% or more below the emission standard                                                                                                           |
|                                       | Opacity          | 1. >250 x 10 <sup>6</sup> Btu/hr<br>2. Exempt if burning gas<br>3. Exempt if burning oil, or a mixture of oil and gas are the only fuels used and the source is able to comply with the applicable particulate matter and opacity standards without installation of control equipment |
| Nitric Acid Plants                    | NO <sub>x</sub>  | 1. >300 ton/day<br>2. Located in a designated non-attainment area for NO <sub>2</sub> .                                                                                                                                                                                               |
| Sulfuric Acid Plants                  | SO <sub>2</sub>  | 1. >300 tons/day                                                                                                                                                                                                                                                                      |
| Petroleum Refineries                  | Opacity          | 1. >20,000 barrels/day                                                                                                                                                                                                                                                                |

Table # 16

NESHAP MONITORING REQUIREMENTS  
FOR VINYL CHLORIDE SOURCES

- I     EDC PLANTS
  - A. All exhaust gases discharged from any equipment used in EDC purification.
  - B. Emissions from each oxychlorination reactor
  
- II    VC PLANTS
  - A. All exhaust gases discharged from any equipment used in vinyl chloride formation.
  
- III   PVC PLANTS
  - A. All exhaust gases discharged from each reactor.
  - B. All exhaust gases discharged from each stripper.
  - C. All exhaust gases discharged from each mixing, weighing or holding container which precedes the stripper (or reactor if plant has no stripper).
  - D. All exhaust gases discharged from each monomer recovery system.
  
- IV    EDC, VC AND PVC PLANTS - ANY CONTROL SYSTEM TO WHICH REACTOR EMISSIONS ARE REQUIRED TO BE DUCTED FROM
  - A. Loading or unloading lines
  - B. Slip gauges
  - C. Manually vented equipment
  - D. Equipment opened to the atmosphere from which vinyl chloride is removed prior to opening
  - E. Inprocess wastewater

VENDORS OF CONTINUOUS  
MONITORING EQUIPMENT

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# VENDORS OF CONTINUOUS MONITORING EQUIPMENT

| VENDORS                                       | SO <sub>2</sub> | NO <sub>x</sub> | Opacity | O <sub>2</sub> | CO <sub>2</sub> | TRS | H <sub>2</sub> S | Data Handling Equipment |
|-----------------------------------------------|-----------------|-----------------|---------|----------------|-----------------|-----|------------------|-------------------------|
| Andersen Samplers, Inc.                       |                 |                 | x       |                |                 |     |                  |                         |
| Babcock and Wilcox Company, Bailey Meter Co.  |                 |                 | x       | x              |                 |     |                  |                         |
| Beckman Instruments, Inc.                     | x               | x               |         | x              |                 |     | x                | x                       |
| The Bendix Corp., Env. and Process Inst. Div. | x               | x               |         |                | x               | x   | x                | x                       |
| Calibrated Instruments, Inc.                  | x               |                 |         |                | x               |     | x                |                         |
| CEA Instruments, Inc.                         | x               | x               |         |                |                 |     | x                |                         |
| Cleveland Controls, Inc.                      |                 |                 |         | x              |                 |     |                  |                         |
| Contraves-Goerz Corporation                   | x               | x               | x       |                | x               |     |                  | x                       |
| Datatest                                      |                 |                 | x       |                |                 |     |                  |                         |
| E. I. Du Pont de Nemours and Company          | x               | x               |         |                |                 | y   | x                | x                       |
| Dynatron, Inc.                                |                 |                 | x       |                |                 |     |                  |                         |
| Electronics Corporation of America            |                 |                 | x       |                |                 |     |                  |                         |
| Energetics Science, Inc.                      |                 | x               |         |                |                 |     | x                |                         |
| Environmental Data Corporation                | x               | x               | x       |                | x               |     | x                | x                       |
| Environmental Tectonics Corp.                 |                 | x               |         |                | x               |     |                  |                         |
| Esterline Angus                               | x               | x               | x       | x              | x               | x   | x                |                         |
| Horiba Instruments, Inc.                      | x               | x               |         |                | x               |     |                  |                         |
| Houston Atlas, Inc.                           |                 |                 |         |                |                 |     |                  |                         |
| Infrared Industries                           |                 |                 |         |                | x               |     |                  |                         |
| Interscan Corporation                         | x               | x               |         |                |                 |     |                  |                         |
| Lear Siegler, Inc.                            | x               | x               | x       | x              |                 |     |                  | x                       |
| Leeds and Northrup Company                    |                 |                 |         | x              | x               |     |                  | x                       |
| Meloy Laboratories, Inc.                      | x               | x               |         |                |                 |     |                  |                         |
| Mine Safety Appliance Company                 | x               | x               |         | x              | x               |     |                  |                         |
| Photomation, Inc.                             |                 |                 | x       |                |                 |     |                  |                         |
| Preferred Instruments, Div.                   |                 |                 | x       |                |                 |     |                  | x                       |
| Research Appliance Company                    |                 |                 | x       |                |                 |     |                  |                         |
| Milton Roy Company                            |                 |                 |         | x              | x               |     |                  |                         |
| Source Gas Analyzers, Inc.                    |                 | x               |         |                |                 |     |                  |                         |
| Taylor Instrument Company                     |                 |                 |         | x              |                 |     |                  | x                       |
| Thermco Instrument Corporation                |                 |                 |         | x              | x               |     |                  |                         |
| Thermo Electron Corporation                   | x               | x               |         |                |                 |     | x                |                         |
| Western Precipitation Division                |                 | x               | x       | x              |                 |     | x                |                         |
| Western Research and Development Ltd.         | x               |                 | x       | x              |                 |     | x                | x                       |
| Whittaker Corporation                         | x               | x               | x       | x              |                 | x   | x                |                         |

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| 16. ABSTRACT<br><br>The Environmental Protection Agency has promulgated revisions to 40 CFR Part 60, New Source Performance Standards, and 40 CFR Part 61, National Emission Standards for Hazardous Air Pollutants that require specified categories of stationary sources to continuously monitor emissions. The EPA has also required States to revise their SIP's to include continuous emission monitoring regulations.<br><br>This report is a compilation of the following continuous emission monitoring information: EPA organizations and personnel involved with continuous emission monitoring; continuous emission monitoring regulations; vendors of continuous monitoring equipment; and a bibliography of continuous monitoring literature. |                                                  |                                                  |
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