United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

EPA-450/2-77-017b
September 1979

Air

EPA

Stationary Gas Turbines

Final EIS

Standard Support and Environmental Impact Statement Volume II: Promulgated Standards of Performance

NSPS

EPA-450/2-77-017b

Stationary Gas Turbines

Standard Support and Environmental Impact Statement Volume II: Promulgated Standards of Performance

Emission Standards and Engineering Division

EPA Project Officer: Doug Bell

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air, Noise, and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

September 1979

This report has been reviewed by the Emission Standards and Engineering Division, Office of Air Quality Planning and Standards, Office of Air, Noise and Radiation, Environmental Protection Agency, and approved for publication. Mention of company or product names does not constitute endorsement by EPA. Copies are available free of charge to Federal employees, current contractors and grantees, and non-profit organizations - as supplies permit - from the Library Services Office, MD-35, Environmental Protection Agency, Research Triangle Park, NC 27711; or may be obtained, for a fee, from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA 22161.

Publication No. EPA-450/2-77-017b

Standard Support and
Final Environmental Impact Statement
for Stationary Gas Turbines

Type of Action: Administrative

Prepared by:

Don R. Goodwin, Director
Emission Standards and Engineering Division
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

6-14-79
(Date)

Approved by:

David G. Hawkins
Assistant Administrator for Air, Noise
and Radiation
U.S. Environmental Protection Agency
Washington, D.C. 20460

JUL 11 1979
(Date)

Final Statement Submitted to EPA's Office of
Federal Activities for Review on

SEP 1979
(Date)

This document may be reviewed at:

Central Docket Section
Room 2903B, Waterside Mall
401 M Street, S.W.
Washington, D. C. 20460

Additional copies may be obtained at:

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

National Technical Information Service
5285 Port Royal Road
Springfield, Virginia 22161

TABLE OF CONTENTS

t

VOLUME II, CHAPTER 1 (SSEIS-GT)

1. SUMMARY

On October 3, 1977, the Environmental Protection Agency EPA) proposed a standard of performance for stationary gas turbines (42 FR 53782) under authority of Section 111 of the Clean Air Act. Public comments were requested on the proposal in the Federal Register publication. There were 78 commenters composed mainly of electric utility and oil and gas producers, as well as gas turbine manufacturing companies. Also commenting were state air pollution control agencies, trade and professional associations, and several Federal agencies. The comments that were submitted, along with responses to these comments, are summarized in this document. The summary of comments and responses serves as the basis for the revisions which have been made to the standard between proposal and promulgation.

1.1 SUMMARY OF CHANGES SINCE PROPOSAL

A number of changes of varying importance have been made since proposal. The most significant of these is to require small gas turbines (less than 10,000 hp) to meet a standard based on dry controls of 150 parts per million (ppm) nitrogen oxides (NO_x). The proposed standard would have required small turbines to meet an emission limit of 75 ppm NO_x. The five-year delay in the effective date for this standard has been retained.

Another change of importance was made to address problems which might be created in areas with limited water supplies. Gas turbines used in oil and gas production or oil and gas transmission are most affected. The promulgated standard includes a requirement that these turbines, that are not located in a Metropolitan Statistical Area (as defined by the Department of Commerce), meet a 150 ppm NO_x emission limit which can be achieved using dry control technology. The proposed standard would have required compliance with the 75 ppm NO_x emissions standard.

One commenter suggested that gas turbines employed for research and development should be exempt due to the nature of such facilities. The promulgated standard includes such an exemption and provides for a case-by-case review to prevent abuses of the intent of the exemption, which is to encourage the advancement of technology in the gas turbine field.

Three changes were made to proposed test methods and monitoring requirements. The promulgated standard allows performance tests to be conducted at maximum and minimum heat rates in the normal operating range and at any two points between these values as opposed to the four fixed points originally proposed. The test method as promulgated also allows a wider span range on NO_x analyzers than originally proposed to accommodate the changes in the standard discussed above. Finally, monitoring of nitrogen and sulfur content in the fuel is allowed on a batch basis in those circumstances where little variation in nitrogen or sulfur content is expected, rather than daily, as proposed.

Several commenters requested flexibility in determining the values of the fuel-bound nitrogen (F) and efficiency (Y) factors used in the equations for calculating allowable emissions of NO_x. Manufacturers of stationary gas turbines will be allowed to determine the fuel-bound nitrogen factors (F) for their various models if they so desire. These fuel-bound nitrogen factors, however, will have a maximum limit of 50 ppm.

Such factors must be approved by the Administrator on a case-by-case basis. The efficiency factor (Y) may be either the manufacturer's or the actual heat rate as opposed to specifying only the manufacturer's heat rate as originally proposed. The changes contained in the promulgated standard are consistent with the intent of the equations as originally proposed.

In some cases commenters were unsure about the meaning of some sections of the standard. In these cases the wording has been changed or expanded to provide additional clarity. The five-year exemption for small gas turbines has been reworded so as to make it clear that the standards can not be applied retroactively. Wording has been added to make it clear that owners/operators may contract for fuel sample analysis and are not required to develop in-house capability. In Reference Method 20 the discussion on the design of moisture traps has been expanded to avoid errors in the use of the method under test conditions where the nitrogen dioxide (NO_x) fraction is greater than 2 or 3 percent.

1.2 SUMMARY OF THE IMPACTS OF THE PROMULGATED ACTION

1.2.1 Alternatives to the Promulgated Action

The alternative control techniques are discussed in Chapter 4 of Volume I of The Standard Support and Environmental Impact Statement (SSEIS,Vol. 1). These alternative control techniques are based upon the best demonstrated technology, considering costs, for stationary gas turbines. The analysis of these alternatives--of taking no action and of postponing the promulgated action--is outlined in Chapter 8 (SSEIS, Vol. I). These alternatives remain the same.

1.2.2 Environmental Impacts of the Promulgated Action

The standard has been changed to allow small stationary gas turbines (less than 10,000 hp) to meet a 150 ppm NO_x standard as opposed to the 75 ppm NO_x originally proposed. The five year delay in the effective date of the standard will still apply to these turbines. An adverse air quality impact will occur because this standard will result in a 40 percent instead of 70 percent reduction in NO_x emissions from turbines of less than 10,000 hp. However, small turbines account for less than 10 percent of the total NO_x emissions from stationary gas turbines. Therefore, the air quality impact of allowing small stationary gas turbines to meet a standard of 150 ppm NO_x emissions is considered reasonable.

The other change which will result in an adverse air quality impact allows turbines employed in oil and gas production or oil and gas transportation to meet a 150 ppm NO_x emission standard originally proposed. The major portion of these turbines consists of turbines less than 10,000 hp and so would be included in the small turbine provision discussed above. There is no additional air quality impact from this group. However, a few turbines employed in oil and gas production or oil and gas transportation are larger than 10,000 hp. The 150 ppm NO_x emission standard results in a 40 percent reduction in NO_x emissions from these turbines as opposed to the 70 percent reduction which would have resulted with the proposed standard of 75 ppm NO_x emissions. However, this increase in NO_x emissions will occur from only those turbines used in oil and gas production or oil and gas transportation and larger than 10,000 hp. This group of turbines accounts for a very small percentage of total NO_x emissions from all stationary gas turbines. Therefore, the impact of this change is considered reasonable.

Energy impacts result from the use of wet control technology as discussed in Chapter 6 Volume I of the Standards Support and Environmental Impact Statement, (SSEIS, Vol. I). The changes since proposal mean that dry control technology will be used to achieve the NO_x emission standard of 150 ppm for small gas turbines and turbines in oil and gas production or oil and gas transportation. Therefore, the promulgated action reduces some of the adverse energy impacts associated with the proposed NO_x emission standard.

1.2.3 Economic Impact of the Promulgated Action

Requiring small gas turbines and turbines in oil and gas production or oil and gas transportation to meet a 150 ppm NO_x emission standard instead of the 75 ppm NO_x emission standard will reduce the economic impact on small turbines. An analysis of the economic impact of the standards based on wet control technology (75 ppm) prior to proposal concluded that these standards were economically feasible for large and small turbines. However, new data show that for some turbines wet control technology cannot be applied in an economically feasible manner.

The costs associated with wet control technology were reexamined with respect to small gas turbines. New figures for the costs of redesigning small gas turbines for use with wet control technology were obtained. These figures indicated that costs had increased two to three times over the original manufacturers' estimates. These increased redesign costs were attributed to a decline in small gas turbine sales, yielding a smaller production base over which the nonrecurring part of the redesign costs could be amortized. As a result of these data, the cost of wet control technology on small turbines now represents a 16 percent increase in capital cost as compared to the 4 percent increase estimated in the SSEIS, Vol. I. This increase in cost is considered unreasonable. Therefore, small gas turbines will be required, by the promulgated standard, to achieve a 150 ppm NO_x emissions standard which can be accomplished using dry control technology, thus reducing the economic impacts discussed above.

The costs associated with wet control technology were reassessed with special emphasis on turbines located on offshore platforms and in arid and remote regions. The extra costs associated with these locations are all related to lack of water of acceptable quality or quantity. When the cost of platform space was factored into the analysis for offshore platforms, the economic impact was as high as a 33 percent increase in capital costs (as compared to 7 percent in the SSEIS, Vol. I). In many arid and remote regions, water would have to be trucked, transported by pipeline, or a large reservoir constructed, none of which is considered economically feasible. Most of these situations are associated with turbines used for oil and gas production or oil and gas transportation. Therefore, the requirement that these turbines meet a 150 ppm NO_x standard, as opposed to the 75 ppm NO_x standard, allows the turbines to use dry control technology and removes these unreasonable impacts.

1.2.4 Other Considerations

1.2.4.1 Adverse Impacts

The potential adverse impacts associated with these standards are discussed in Chapters 1 and 6 (SSEIS, Vol. I). These impacts remain essentially unchanged since proposal. However, for the water impacts, the trend toward dry controls which is further encouraged by the changes since proposal will result in a more widespread use of dry control technology and, therefore, reduce the impact on water resources.

1.2.4.2 Relationship Between Local Short-Term Uses of Man's Environment and the Maintenance and Enhancement of Long-Term Productivity

This impact is discussed in Chapters 6 and 8 of the SSEIS, Vol I and remains unchanged since proposal.

1.2.4.3 Irreversible and Irretrievable Commitments of Resources

This impact is discussed in Chapter 6 of the SSEIS, Vol I and remains unchanged since proposal.

2. SUMMARY OF PUBLIC COMMENTS

The list of commenters and their affiliations is shown in Table 2-1. Seventy-eight letters contained comments on the proposed standard and Volume I of the Standards Support and Environmental Impact Statement. The significant comments have been combined into the following eight major areas:

1. General
2. Emission Control Technology
3. Modification and Reconstruction
4. Economic Impact
5. Environmental Impact
6. Energy Impact
7. Legal Considerations
8. Test Methods and Monitoring

The comments and issues and responses to them are discussed in the following section of this chapter. A summary of the changes to the regulations is included in Section 2 of Chapter 1.

2.1 GENERAL

Test Facilities

Exemptions were requested by several commenters for temporary and intermittent operation of gas turbines to permit research and development.

It was considered reasonable to exempt gas turbines involved in research and development testing of equipment. Therefore, gas turbines involved in research and development for the purpose of improving combustion efficiency or developing control technology are exempt from the NO_x emission limit in the promulgated standards. Gas turbines involved in this type of research and development generally operate intermittently and on a temporary basis. The exemptions, therefore, will be allowed on a case-by-case basis as determined by the Administrator.

Five-year Exemption

Small stationary gas turbines with heat input at peak load between 10.7 and 107.2 gigajoules per hour (between 10 million Btu/hr and 100 million Btu/hr) are exempt from the standards for a period of five years from the date of proposal. Some commenters felt that it was not clearly stated that these gas turbines which are exempt for this five year period would not be required to be retrofitted with NO_x emissions controls after the exemption period ended. These commenters felt the intent of the New Source Performance Standard (NSPS) was not to require such retrofitting, and they recommended that the standard be reworded to explicitly state that intention.

The commenters' understanding of the intent of the standard on this point is correct. Gas turbines with a heat input at peak load between 10.7 and 107.2 gigajoules per hour which have commenced construction on or before the end of the five year exemption period will be considered existing facilities. These facilities will not have to retrofit at the end of the exemption period. This point has been clarified in the promulgated standards.

2.2 EMISSIONS CONTROL TECHNOLOGY

Choice of Wet Control as Basis for Standard

The selection of water injection as the best system of emission reduction for stationary gas turbines was criticized by a number of commenters. These commenters pointed out that although dry controls will not reduce emissions as much as wet controls, dry controls will reduce NO_x emissions without the objectionable results of water injection, i.e., increased fuel consumption and difficulty in securing water of acceptable quality. These commenters, therefore, recommended postponement of standards until such time as dry controls are feasible.

As pointed out in Volume 1 of the Standards Support and Environmental Impact Statement (SSEIS), a high priority for control of NO_x emissions has been established. Wet and dry controls were considered as the only viable alternative control techniques for reducing NO_x emissions from gas turbines. NO_x emissions control achievable with these two alternatives clearly favored the development of standards of performance based on wet controls from an environmental viewpoint. Reductions in NO_x emissions of more than 70 percent have been demonstrated using wet controls on many large gas turbines (greater than 10,000 horsepower) used in utility and industrial applications. Thus, wet controls can be applied immediately to large gas turbines, which account for 85 - 90 percent of NO_x emissions from gas turbines.

The technology of wet control is the same for both large and small gas turbines, the manufacturers of small gas turbines, however, have not experimented with or developed this technology to the same extent as the manufacturers of large gas turbines. In addition, small gas turbines tend to be produced on more of an assembly line basis than large gas turbines. Consequently, the manufacturers of small gas turbines need a lead time of five years (based on their estimates) to design test and incorporate wet controls on small gas turbines.

Even with a five year delay in application of standards to small turbines, standards of performance based on wet controls will reduce national NO_x emissions by about 190,000 tons per year by 1982. Therefore, the reduction in NO_x emissions resulting from standards based on wet controls is significant.

Dry controls have demonstrated NO_x emissions reduction of only about 40 percent in laboratory and combustor rig tests. Because of the advanced state of research and development into dry control by the manufacturers of large gas turbines, the much larger lead time involved in ordering large gas turbines, and the greater attention that can be given to "custom" engineering design of large gas turbines, dry controls can be implemented on large gas turbines immediately. Manufacturers of small gas turbines estimated, however, that it would take as long to incorporate dry controls as wet controls on small gas turbines. Basing the standard only on dry controls, therefore, would significantly reduce the amount of NO_x emissions reductions achieved.

The economic impact of standards of performance based on wet controls is considered reasonable for large gas turbines. (See Economic Impact Discussion.) Thus, wet controls represent "... the best technological system of continuous emission reduction ... (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) ..." for large gas turbines.

The economic impact of standards based on wet controls, however, is considered unreasonable for small gas turbines, gas turbines located on offshore platforms, and gas turbines employed in oil or gas production and transportation which are not located in a Metropolitan Statistical Area. The economic impact of standards based on dry controls, on the other hand, is considered reasonable for these gas turbines. (See Economic Impact Discussion.) Thus, dry controls represent "... the best system of continuous emission reduction ... (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and and energy requirements) ..."for small gas turbines, gas turbines located on offshore platforms, and gas turbines employed in oil or gas production and transportation which are not located in a Metropolitan Statistical Area.

Volume 1 of the SSEIS summarizes the data and information available from the literature and other nonconfidential sources concerning the effectiveness of dry controls in reducing NO_x emissions from stationary gas turbines. More recently, additional data and information have been published in the Proceedings of the Third Stationary Source Combustion Symposium (EPA-600/7-79-050C), Advanced Combustion Systems for Stationary Gas Turbines (interim report) prepared by the Pratt and Whitney Aircraft Group for EPA (Contract 68-02-2136), "Experimental Clean Combustor Program Phas III" (NASA CR-135253) also prepared by the Pratt and Whitney Aircraft Group for the National Aeronautics and Space

Administration (NASA), and "Aircraft Engine Emissions" (NASA Conference Publication 2021). These data and information show that dry controls can reduce NO_x emissions by about 40 percent. Multiplying this reduction by a typical NO_x emission level from an uncontrolled gas turbine of about 250 ppm leads to an emission limit for dry controls of 150 ppm. This, therefore, is the numerical emission limit included in the promulgated standards for small gas turbines, gas turbines located on offshore platforms, and gas turbines employed in oil or gas production or transportation which are not located in Metropolitan Statistical Areas.

The five year delay from the date of proposal of the standards in the applicability date of compliance with the NO_x emission limit for small gas turbines has been retained in the promulgated standards. As discussed above, manufacturers of small gas turbines have estimated that it will take this long to incorporate either wet or dry controls on these gas turbines.

Fuel-Bound Nitrogen Allowance

Several commenters criticized the fuel-bound nitrogen allowance included in the proposed standards. It was generally felt that due to the limited data on conversion of fuel-bound nitrogen to NO_x, greater flexibility in the equations used to calculate the fuel-bound NO_x emissions contribution should be permitted. These commenters recommended that manufacturers be allowed to develop their own fuel-bound nitrogen allowance.

As discussed in Volume I of the SSEIS, the reaction mechanism by which fuel-bound nitrogen contributes to NO_x emissions is not fully understood and NO_x emission data are limited with respect to fuels containing significant amounts of fuel-bound nitrogen. The problem of quantifying the fuel-bound nitrogen contribution to total NO_x emissions in gas turbines is further complicated by the fact that the amount of nitrogen in the fuel has an effect on the degree of conversion.

In light of this sparcity of data, the commenters' recommendation seems reasonable. Therefore, a provision has been added to the standard to allow manufacturers to develop their own fuel-bound nitrogen allowances for each gas turbine model they manufacture. Such allowance factors, however, must be approved by the Administrator on a case-by-case basis before the initial performance test required by §60.8 of the General Provisions. Petitions by manufacturers for fuel-bound nitrogen allowance factors must be supported by data which clearly provide a basis for determining the contribution of fuel-bound nitrogen to total NO_x emissions from the gas turbine. However, the amount of organic NO_x emissions allowed under any fuel-bound nitrogen allowance factor shall not exceed 50 ppm (Also discussed in Section 2.6, Synthetic Fuels, below). Notice of approval of the use of these factors for various gas turbine models will be given in the Federal Register.

Ambient Correction Factors

Some commenters requested that parameters other than ambient conditions be included in ambient correction factors. These commenters pointed out that the use of such parameters as combustor inlet temperature, fuel flow, and fuel-to-air ratio should be allowed. Since the majority of research and development work in this area focuses on these parameters, the proposed standard, in effect, requires that manufacturers develop new correction equations. They felt that this is wasteful of both engineering and engine test time.

With respect to ambient correction factors, the intent of the standard is to avoid using parameters which are difficult to measure or are machine-dependent and thus subject to variation due to factors other than ambient conditions. In order to ensure that standards of performance are enforced uniformly, the effect of ambient atmospheric conditions on NO_x emission levels should be based on those parameters which are common to all machines, easily measured, and independent of individual design or configuration. Consequently, the correction factor must be developed in terms of only the following variables: ambient air pressure, ambient air humidity, and ambient air temperature.

Operation at Partial Load

The proposed standard would have required that the water-to-fuel ratio needed for compliance with the NO_x emission limit be determined at 30, 50, 75 and 100 percent of peak load during the initial performance test. One commenter objected to this requirement, stating the requirement of emission measurements at specific load condition may not be appropriate for all gas turbine applications, and it is difficult to design a single water injection system to operate over as wide a range as will be required if water injection is required over a wide turbine operating range.

The commenter pointed out that certain gas turbines may not physically be able to operate between 30 and 100 percent of peak rating of the turbine unit. Examples of such operations cited were: gas turbines in industrial generation service; cogeneration systems; gas turbines driving mechanical loads, such as pumps or compressors or other systems dedicated to a single, specific load; and gas turbines with a minimum load range.

In light of these comments, the standard has been changed to permit testing " . . . at four points in the normal operating range of the gas turbine, including the minimum and maximum points in this range." It should not be construed from this new wording, however, that compliance with the standard is not required outside this range. Compliance with the standard is required at all times during operation.

The commenter's second objection seems to be based on the assumption that water injection would be required over the entire operating range of a gas turbine to comply with the standard, and that this would require a complex water injection system to accomodate the wide range of water flow rates. The commenter recommends, therefore, that gas turbines operating at 30 percent load or less be exempt from compliance with the standard.

The standard does not require injection of water, but, rather, compliance with an NO_x numerical emission limit. Emissions of NO_x are relatively sensitive to load, and as load decreases, emissions decrease fairly rapidly. Consequently, it is not likely that water injection will be required at low loads, i.e., less than 30 percent, to comply with the standard. Thus exempting gas turbines from compliance with the standard at low loads does not seem reasonable.

2.3 MODIFICATION AND RECONSTRUCTION

Definitions

Some commenters objected to lack of definitions for the terms "modification" and "reconstruction" within the standards. According to these commenters, the word "reconstruction" needs clarification since it could be misconstrued to include existing gas turbines simply undergoing periodic overhauls.

The terms, "modification" and "reconstruction," while not explicitly defined in Subpart GG, Standards of Performance for Stationary Gas Turbines, have been thoroughly defined in Subpart A, the General Provisions, which are applicable to all standards of performance. For a complete discussion of the meaning of these terms, the commenter is referred to the General Provisions.

Modification essentially means any change of an existing facility which increases the amount of a pollutant emitted into the atmosphere by that facility. Conditions which do not constitute modification include among other things: (1) maintenance, repair, and replacement which are "routine"; (2) an increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure; (3) an increase in the hours of operation; (4) use of an alternative fuel under certain conditions within the limitations as set forth in Section 60.14(e); (5) the addition or use of any system or device, the primary function of which is the reduction of air pollutants, except when such device is determined by the Administrator to be less environmentally beneficial; and (6) the relocation or change in ownership of an existing facility.

Reconstruction essentially means the alteration of an existing facility to such an extent that the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a completely new facility and it is technologically and economically feasible to meet the applicable standards.

In light of the definition of modification and reconstruction in the General Provisions, they need not be reiterated in Subpart GG.

Conversion From Natural Gas To Oil

Some commenters felt that existing gas turbines which now burn natural gas and are subsequently altered to burn oil should be exempt from consideration as modifications. The high cost and technical difficulties of compliance with the standards would discourage fuel switching to conserve natural gas supplies.

As outlined in the General Provisions of 40 CFR Part 60, which are applicable to all standards of performance, most changes to an existing facility which result in an increase in emission rate to the atmosphere are considered modifications. However, according to section 60.14(e)(4) of the General Provisions, the use of an alternative fuel or raw material shall not be considered a modification if the existing facility was designed to accommodate that alternative use. Therefore, if a gas turbine is designed to fire both natural gas and oil, then switching from one fuel to the other would not be considered a modification even if emissions were increased. If a gas turbine that is not designed for firing both fuels is switched from firing natural gas to firing oil, installation of new injection nozzles which increase mixing to reduce NO_x production, or installation of new NO_x combustors currently on the market, would in most cases maintain emissions at their previous levels. Since emissions would not increase, the gas turbine would not be considered modified, and the real impact of the standards on gas turbines switching from natural gas to oil will probably be quite small. Therefore, no special provisions for fuel switching have been included in the promulgated standards.

2.4 ECONOMIC IMPACT

Operation and Maintenance

Several commenters stated that if water injection is used to meet the NSPS, maintenance costs could increase significantly. One reason cited for increased maintenance costs was that chemicals and minerals in the water would likely be deposited on the internal surfaces of gas turbines, such as turbine blades, leading to downtime for repair and cleaning. In addition, the commenters felt that higher maintenance requirements could be expected due to the increased complexity of a gas turbine with water injection.

As pointed out in Volume I of the SSEIS, to avoid deposition of chemicals and minerals on the gas turbine blades, the water used for water injection must be treated. The costs for water treatment were included in overall costs of water injection systems and, for large gas turbines, these costs are considered reasonable.

Actual maintenance and operating costs for gas turbines operating with water or steam injection are limited. Several major utilities, however, have accumulated significant amounts of operating time on gas turbines using water or steam injection for control of NO_x emissions. There have been some problems attributable to the water or steam injection systems, but based on the data available, these problems have been confined to initial periods of operation of these systems. Most of these reported problems, such as turbine blade damage, flame-outs, water hammer damage, and ignition problems, were easily corrected by minor redesign of the equipment hardware. Because of the knowledge gained from these first few systems, such problems should not arise in the future.

As mentioned, some utilities have accumulated substantial operating experience without any significant increase in maintenance or operating costs or other adverse effects. For example, one utility has used water injection on two gas turbines for over 55,000 hours without making any major changes to their normal maintenance and operating procedures. They followed procedures essentially identical to those required for a similar machine not using water injection, and the plant experienced no outages attributable to the water injection system. Another company has accumulated over 92,000 hours of operating time with water injection on 17 turbines with approximately only 116 hours of outage attributable to their water injection system. Increased maintenance costs which can be attributed to these water injection systems are not available, as such costs were not accounted for separately from normal maintenance. However, they were not reported as significant.

<u>Water Injection Costs</u>

Some commenters expressed the opinion that the cost estimates for controlling NO_x emissions from large gas turbines were too low. Accordingly, these commenters felt that wet control technology should not be the basis of the standards for large stationary gas turbines.

The costs associated with wet control technology, as applied to large gas turbines, were reassessed. In a few cases, it appared the water to fuel ratio used in Volume I of the SSEIS was somwhat low. In these cases the capital and annualized operating costs associated with wet control on large gas turbines were revised to reflect injection of more water into the gas turbine. Noe of these revisions, however, resulted in a significant change in the projected economic impact of wet controls on large gas turbines. Thus, depending on the size and end use of large gas turbines wet controls are still projected to increase capital and annualized operating costs by no more than 1 to 4 percent. Increases of this order of magnitude are considered reasonable in light of the 70 percent reduction in NO_x emissions achieved by wet controls. Consequently, the basis of the promulgated standards for large gas turbines remain the same as that for the proposed standards -- wet controls.

A number of commenters also expressed the opinion that the cost estimates for wet controls to reduce NO_x emissions from small gas turbines were too low. Therefore, the standards for small gas turbines should not be based on wet controls.

Information included in the comments submitted by manufacturers of small gas turbines indicated the cost of redesigning these gas turbines for water injection are much greater than those included in Volume 1 of the SSEIS. Consequently, it appears the costs of water injection would increase the capital cost of small gas turbines by about 16 percent, rather than about 4 percent as originally estimated. Despite this increase in capital costs, it does not appear water injection would increase the annualized operating costs of small gas turbines by more than 1 to 4 percent as originally estimated, due to the predominance of fuel costs in operating costs. An increase of 16 percent in the capital cost of small gas turbines, however, is considered unreasonable.

Very little information was presented in Volume 1 of the SSEIS concerning the costs of dry controls. The conclusion was drawn, however, that these costs would undoubtedly be less than those associated with wet controls.

Little information was also included in the comments submitted by the manufacturers of small gas turbines concerning the costs of dry controls. Most of the cost information dealt with the costs of wet controls. One manufacturer, however, did submit limited information which appears to indicate that the capital cost impact of dry controls on small gas turbines might increase the capital costs of small gas by about 4 percent and the annualized operating costs by about 1 to 4 percent. The magnitude of these impacts is essentially the same as those originally associated with wet controls in Volume 1 of the SSEIS, and they are considered reasonable. Consequently, the basis of the promulgated standards for small gas turbines is dry controls.

Arid And Remote Regions

A number of commenters stated that the costs associated with wet controls on gas turbines located on offshore platforms, and in arid and remote regions were unreasonable. These commenters felt that the costs of obtaining, transporting, and treating water in these areas prohibited the use of water injection.

As mentioned by the commenters, the cost associated with water injection on gas turbines in these locations are all related to lack of water of acceptable quality or quantity. Review of the original estimated costs associated with employing water injection on gas turbines located on offshore platforms indicates that the required expenditures for platform space were not incorporated into these estimates. Platform space is very expensive; typical space on an offshore platform averages approximately $400 per square foot. When this cost is factored in, use of water treatment systems to provide water for NO_x emissions control would increase the capital costs of a gas turbine by approximately 33 percent (as compared to an original estimate of 7 percent in Volume I of the SSEIS). This represents an unreasonable economic impact.

Dry controls, unlike wet controls, would not require additional space on offshore platforms. Although most gas turbines located on offshore platforms would be considered small gas turbines under the standards, it is possible that some large gas turbines might be located on offshore platforms. Therefore, all the information available concerning the costs associated with standards based on dry controls for large gas turbines was reviewed.

Unfortunately, no additional information on the costs of dry controls was included in the comments submitted by the manufacturers of large gas turbines. As mentioned above, the information presented in Volume 1 of the SSEIS is very limited concerning the costs of dry controls, although the conclusion is drawn that these costs would undoubtedly be less than the cost of wet controls. It also seems reasonable to assume that the costs of dry controls on large gas turbines would certainly be less than the costs of dry controls on small gas turbines. Consequently, standards based on dry controls should not increase the capital and annualized operating costs of large gas turbines by more than the 1 to 4 percent projected for small gas turbines. This conclusion even seems conservative in light of the projected increase in capital and annualized operating costs for wet controls on large gas turbines of no more than 1 to 4 percent. In any event, the costs of standards based on dry controls for large gas turbines are considered reasonable. Therefore, the promulgated standards for gas turbines located on offshore platforms are based on dry controls.

In many arid and remote regions, gas turbines would have to obtain water by trucking, installing pipelines to the site, or by construction of large water reservoirs. While costs included in Volume I of the SSEIS do not show trucking of water to be unreasonable, these costs are not based on actual remote area conditions. That is, these costs are based on paved road conditions and standard ICC freight rates. However, the gas turbines located in remote regions are not likely to have good access roads. Consequently, it is felt that in most cases the costs of trucking, laying a pipeline, or constructing a reservoir are unreasonable for arid and remote areas.

A number of alternatives were examined to provide some sort of exemption for gas turbines in water-limited areas. In all cases exemption from the 75 ppm NO_x emissions standard means compliance with a 150 ppm NO_x emission standard based on dry controls. One category of gas turbines for which it is clear that an exemption is necessary is offshore platform turbines. Wet control technology cannot be used in offshore situations in a manner that would be considered economically reasonable.

For other situations, defining the nature of the exemption was more difficult. Four options were considered. The terms "arid" and "remote" could be defined and all turbines located in these areas could be exempt. While this option is conceptually straightforward, the actual determination of such areas would be extremely difficult. Another method of exemption considered was to exempt all gas turbines located more than a specified distance from an adequate water supply. Defining adequate water supply and determining a distance which would be equitable in all locations and under all circumstances proved to be as difficult as the first option.

Another option was to provide a case-by-case exemption based on demonstrated costs of control. This approach assures that all cases are covered and that each is justified. This approach, however, would encourage estimation of grossly inflated costs to justify exemption. In addition it would place an unreasonable burden on both EPA and the industry. Therefore, this approach was considered unreasonable.

Finally, it became apparent that gas turbines located in arid and remote regions could generally be classified by end use in many cases. Most gas turbines located in arid or remote regions are used for either oil and gas production, or oil and gas transportation. Included in this category are offshore platform, pipeline, and production field gas turbines. These gas turbines are generally less than 10,000 horsepower and thus would be exempt from a standard based on wet control technology due to size alone, as discussed earlier in this section. However, a number of the gas turbines used in oil and gas production and transportation are larger than 10,000 horsepower.

In light of these considerations, the standard has been revised to require gas turbines employed in oil and gas production or oil and gas transportation and not located in a Metropolitan Statistical Area (as defined by the Department of Commerce) to meet an emission limit based on dry control technology of 150 ppm NO_x emissions. As discussed earlier in this section, dry controls are available and can achieve 40 percent reduction in NO_x emissions. The total capacity that is represented by these gas turbines is small, and exempting them from the 75 ppm NO_x emissions level based on wet control technology will not adversely impact the overall NO_x emissions reduction achieved by this standard as originally proposed. Those gas turbines employed in oil and gas production or oil and gas transportation that are located in a Metropolitan Statistical Area (MSA) are still required to meet the 75 ppm NO_x emission limit because in an MSA a suitable water supply for water injection will be available.

Gas turbines employed for electric generation, however, will be required to meet the 75 ppm NO_x standard. Electric generation gas turbines are generally much larger than oil or gas production and transmission gas turbines and are considered such significant sources of NO_x that exempting such turbines is not considered reasonable. Of course, this pertains only to gas turbines greater than 10,000 hp because small gas turbines, as discussed above, are required to meet a 150 ppm emission limit. In addition, manufacturers have expressed optimism that dry control technology for large electric generation gas turbines will be able to achieve the 75 ppm NO_x standard without water injection in the very near future. In fact, some manufacturers are now taking orders for large gas turbines guaranteed to meet the 75 ppm NO_x emission standard using dry control technology.

2.5 ENVIRONMENTAL IMPACT

Significance of Air Quality Improvement

The degree of air quality improvement achieved by the standards was questioned by numerous commenters. A general comment was that the amount of NO_x emission reduction projected in Volume I of the SSEIS, is not worth the increased costs and adverse energy impact associated with wet control systems installed on gas turbines.

Stationary gas turbines are significant contributors to nationwide emissions of NO_x. A high priority has been assigned to the development of standards of performance for major NO_x emission sources wherever significant reductions can be achieved. As pointed out in the SSEIS, applying best technology to all new sources would reduce the growth of national NO_x emissions from stationary sources but would not prevent increases from occurring. In fact, national NO_x emissions would still increase by about 25 percent. Stationary gas turbines were selected for standards development because they are significant sources of NO_x emissions and control technology is available to reduce these emissions at reasonable costs.

Some commenters also maintained that the characteristic high plume rise of gas turbines results in negligible ground level concentrations, which are not apt to be improved much by use of wet controls.

Standards of performance are designed to reflect best demonstrated control technology (considering costs) for affected sources. The overriding purpose of the collective body of standards is to improve existing air quality and to prevent new pollution problems from arising, not to achieve specific ambient air quality goals.

While it is true that simple cycle gas turbines have characteristically high plume rise, this is due to the extraordinarily high exhaust gas temperatures (on the order of 800? - 1100?F). Plumes from combined cycle and regenerative cycle gas turbines, however, does not share this characteristic because their exhaust temperatures are much lower (on the order of 200? - 400?F). In these cases, ground level NO_x concentrations can be significant and the standard will reduce these concentrations appreciably.

Adverse Water Impact

One frequent criticism concerned the potential impact of the standards on the nation's water supply. Commenters stated that the impact on water resources has not been adequately considered. The commenters pointed out that wet controls could result in water shortages in some areas of the country and that the effluent from water treatment necessary for wet controls could create water pollution problems. One commenter suggested exemptions in the standards for periods of drought.

The potential water pollution impact of standards based on wet controls is minimal. The only potential source of water pollution is from the treatment system for water used to control NO_x emissions. The quality of the wastewater is essentially the same as that of the influent water except that the concentration of total dissolved solids in the waste stream is about three to four times that of the influent. The owner/operator of the gas turbine would need a permit for the discharge, and, while treatment requirements of the discharge may vary by locale, in most cases, the effluent may be sewered directly or returned to the river, lake, or other natural source.

The quantity of water required by a stationary gas turbine using wet controls is relatively small. Even at a water-to-fuel ratio of 1:1 (a worst case estimate, with 0.6:1 or 0.7:1 more typical), a gas turbine using wet controls consumes only five percent of a comparably sized steam boiler using cooling towers. Since 90 percent of the total U.S. gas turbine capacity is utilized for electricity generation, for which the only viable alternative would in fact be steam boiler utilization, the impact of using wet controls on water supplies is quite reasonable.

The remainder of the U.S. gas turbine capacity is generally represented by turbines smaller than 10,000 hp and, for this group, the standard will have no impact on water supplies since, as discussed earlier, these turbines will use dry controls to meet the 150 ppm standard which becomes effective five years after promulgation. The five-year exemption for small gas turbines was explicitly selected in order to provide manufacturers the time needed to implement dry control technology.

In addition, manufacturers will incorporate dry controls on gas turbines of all sizes as quickly as this technology is developed. This trend toward dry controls would tend to further lessen any impact the standard would have on water pollution or water supplies.

In specific instances of drought in a local geographical area, however, where temporary mandatory water restrictions are placed on homeowners by governmental agencies, it seems reasonable to allow temporary exemptions from the standards for gas turbines operating with water injection for NO_x control. Such an exemption has been incorporated into the standards; these exemptions, however, are to be determined by the Administrator on a case-by-case basis.

Peaking Gas Turbines

A number of commenters felt gas turbines used as "peaking" units should be exempt. Peaking units operate relatively few hours per year (approximately 1,500). According to commenters, use of water injection would result in a very small reduction in annual NO_x emissions and negligible improvement in ground level concentrations.

Standards of performance under Section 111 of the Clean Air Act must reflect the use of the best system of emission reduction (considering costs). The objective of Section 111 is to improve existing air quality as older industrial sources of air pollution are replaced with new industrial sources and to prevent new pollution problems from arising.

As pointed out in Volume I of the SSEIS, about 90 percent of all new gas turbine capacity is expected to be installed by electric utility companies to generate electricity, and possibly as much as 75 percent of all NO_x emissions from stationary gas turbines are emitted from these installations. Of these electric utility gas turbines, a large majority are used to generate power during periods of peak demand. Consequently, by their very nature, peaking gas turbines tend to operate when the need for emission control is greatest, that is, when power demand is highest and air quality is usually at its worst. Therefore, it does not seem reasonable to exempt peaking gas turbines from compliance with the standards.

2.6 ENERGY IMPACT

Synthetic Fuel

A number of writers commented on the potential impact of the standards on the use of shale oil, coal-derived, and other synthetic fuels. It was generally felt that these types of fuels should not be covered by the standards at this time, since this could hinder further development of these fuels. Commenters recommended that EPA wait until such fuels are available and being fired successfully in gas turbines and then set the fuel-bound nitrogen allowance for these fuels based on actual data.

Total NO_x emissions from any combustion source, including stationary gas turbines, are comprised of thermal NO_x and organic NO_x. Thermal NO_x is formed in a well-defined high temperature reaction between oxygen and nitrogen in the combustion air. Organic NO_x is produced by the combination of fuel-bound nitrogen with oxygen during combustion in a reaction that is not yet fully understood. Shale oil, coal-derived, and other synthetic fuels have high nitrogen content and, therefore, produce relatively high organic NO_x emissions.

Control technology for gas turbines is effective for reducing thermal NO_x, but not for reducing organic NO_x. Thermal NO_x emissions can be reduced by 40 percent with dry control technology and by 70 percent with wet control technology. Organic NO_x emissions are not reduced by wet control technology. The amount of organic NO_x reduction achieved by dry control technology, if any, is uncertain.

As fuel-bound nitrogen increases, the organic NO_x emissions from a gas turbine with thermal NO_x control become a predominant fraction of total NO_x emissions (See Figure 2-1). Consequently, the standards must address in some manner the increased NO_x emissions caused by fuel-bound nitrogen. Since NO_x emission control technology is not effective in reducing organic NO_x emissions from gas turbines, the possibility of basing standards on removal of nitrogen from the fuel prior to combustion was considered as an alternative. The cost of removing nitrogen from the fuel ranges from \$2.00 - \$3.00 per barrel. Nitrogen removal from the fuel, therefore, is not considered reasonable, as the basis for standards of performance.

Two other alternatives were considered. Gas turbines using high nitrogen fuels could be exempt from the standards, as some commenters requested. Exempting turbines from the standard based on the type of fuel used, however, would not require best available control technology in cases where the application of such technology is feasible. The purpose of the NSPS is to reduce NO_x emissions using the best demonstrated technological system of continuous emission reduction, considering costs.

The other alternative considered would establish a fuel-bound nitrogen allowance. Beyond some point it is simply not reasonable to allow combustion of high nitrogen fuels. In addition, high nitrogen fuels, including shale oil and coal-derived fuels, can be used in other combustion devices in which control of organic NO_x emissions is possible. In fact, utility boilers can achieve 30 - 50 percent reduction in organic NO_x emissions. Greater reduction of nationwide NO_x emissions could be achieved

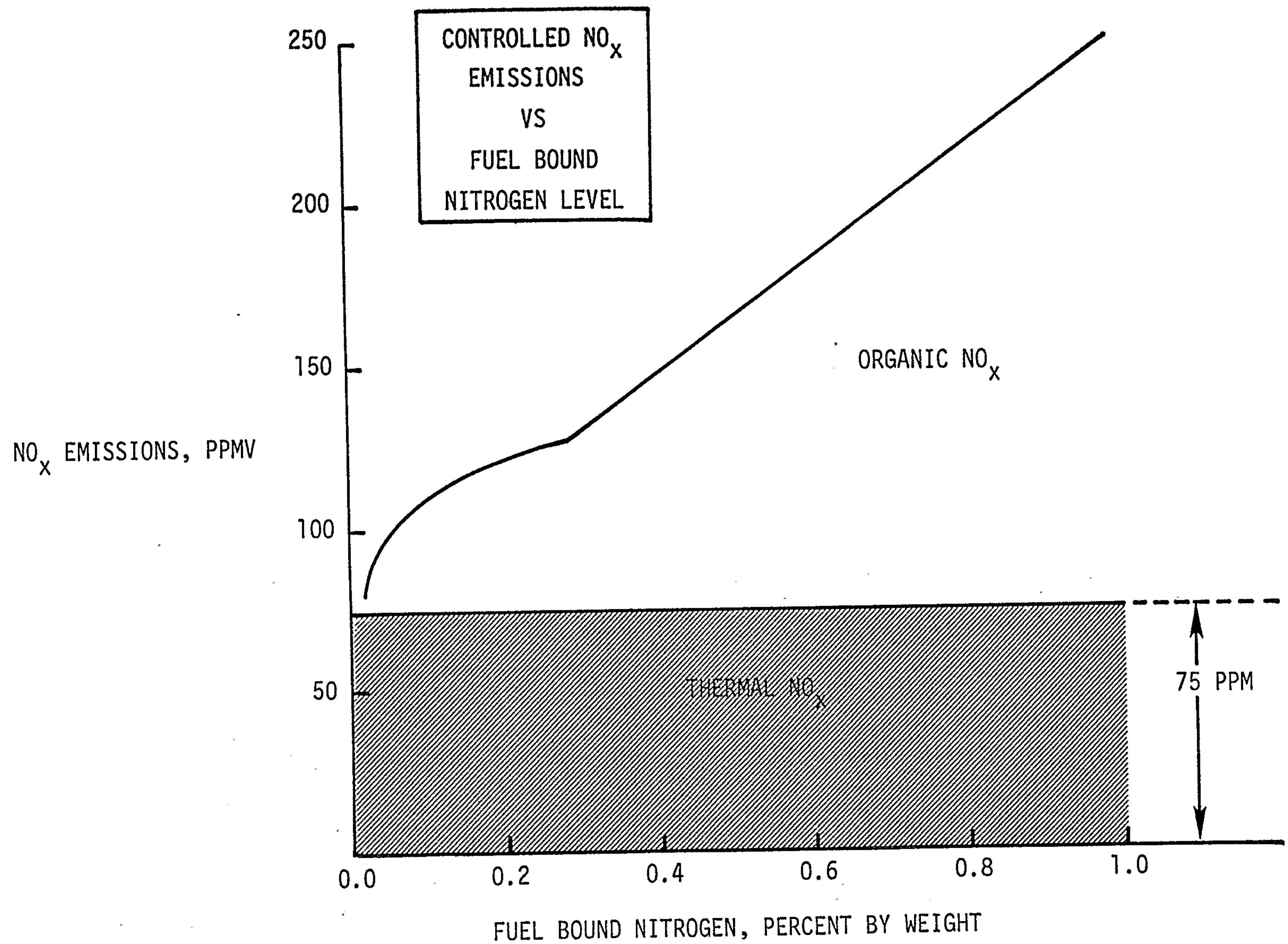

Figure 2-1. Controlled NO_x emission levels vs fuel-bound nitrogen level

by utilizing these fuels in facilities where organic NO_x emissions control is possible rather than in gas turbines where organic NO_x emissions are essentially uncontrolled. Therefore, this approach would balance the trade-off between allowing unlimited selection of fuels and controlling NO_x emissions.

Low nitrogen fuels, such as premium distillate fuel oil and natural gas, are now being fired in nearly all stationary gas turbines. However, energy supply considerations may cause more gas turbines to fire heavy fuel oils and synthetic fuels in the future. A standard based on present practice of firing low nitrogen fuels, therefore, would too rigidly restrict the use of high nitrogen fuel, especially in light of the uncertainty in world energy markets. This is clearly not desirable.

A limited fuel-bound nitrogen allowance which would allow NO_x emissions above the NO_x emission standard is most reasonable. An upper limit of 50 ppm NO_x was selected because such a limit would allow approximately 50 percent of existing heavy fuel oils to be fired in stationary gas turbines (for a more detailed discussion of the fuel-bound nitrogen allowance the reader is referred to Volume I, Chapter 8 of the SSEIS). The fuel-bound nitrogen allowance is considered a reasonable means of allowing flexibility in the selection of fuels while retaining effective control of total NO_x emissions from stationary gas turbines.

Efficiency Correction Factor

One commenter requested that the heat rate term (Y) in the efficiency correction equation for calculating the allowable NO_x emission concentration be redefined to permit substitution of a more appropriate value whenever operating parameters or equipment changes are made by the owner/operator that increase gas turbine thermal efficiency.

If operating changes are made which increase gas turbine thermal efficiency, it does not seem reasonable to use a heat rate which is no longer appropriate. Therefore, the heat rate term Y has been redefined as the manufacturer's rated heat rate at manufacturer's rated peak load, or the actual heat rate as measured at peak load for the gas turbine.

A number of commenters felt that the efficiency correction factor included in the standard should use the overall efficiency of a gas turbine installation rather than the thermal efficiency of the gas turbine itself. For example, many commenters recommended that the overall efficiency of a combined cycle gas turbine installation should be used in this correction factor.

Section 111 of the Clean Air Act requires that standards of performance for new sources reflect the use of the best system of emission reduction. Water injection is considered the best system of emission control for reducing NO_x emissions from stationary gas turbines. To be consistent with the intent of Section 111, the standards must reflect the use of water injection in the gas turbine, independent of any ancillary waste heat recovery equipment which might be associated with a gas turbine. To allow an upward adjustment in the NO_x emission limit based on the efficiency of the combined cycle gas turbine and boiler could mean that water injection might not have to be applied to the gas turbine. Thus, the standards would not be as effective or stringent as they would be if they were based on the efficiency of the gas turbine alone, and this would imply that the standards would not reflect the use of the best system of emission reduction. Therefore, the use of the efficiency factor must be based on the gas turbine efficiency itself, not the overall efficiency of the gas turbine combined with other equipment.

Several commenters felt the efficiency correction factor should be exponential rather than linear. They made the point that since NO_x emissions theoretically increase exponentially with efficiency, it appears inconsistent to allow only a linear increase in emissions for increased efficiency. The commenters further stated that a linear correction could discourage use of more efficient gas turbines at some point.

As discussed in Volume I of the SSEIS, it is simply not reasonable from an emission control viewpoint to select an exponential efficiency adjustment factor. Such an adjustment would at some point allow very large increases in emissions for very small increases in efficiency. The objective of the efficiency adjustment factor is to give an emissions credit for the lower fuel consumption of high efficiency gas turbines. Since fuel consumption of gas turbines varies linearly with efficiency, a linear efficiency adjustment factor is included in the standards to permit increased NO_x emissions from high efficiency gas turbines.

2.7 LEGAL CONSIDERATIONS

Priority List for Stationary Sources

Four comments were received regarding legal considerations. One comment was that the proposed standard does not address the statutory scheme as set forth in Section 111(f), as amended in August, 1977. Section 111(f) requires EPA to establish a priority list, by August 7, 1978, of the categories of major stationary sources that had not been listed under Section 111 by August 7, 1977. In the commenter's view, development of standards for gas turbines, as well as development of other standards for sources listed as of August 7, 1977, must halt pending publication of the priority list.

This conclusion is not supported by the legislative history of Section 111(f). The purpose of the priority list is to ensure that all categories of major stationary sources are regulated promptly under Section 111. There is no indication that development of any standards should halt pending the development of the priority list. Such a halt could well last a year (the time allowed for publication of the priority list), and a year's delay would substantially impair EPA's ability to complete the task of regulating all categories of major stationary sources by 1982 as required in Section 111.

Public Hearing Opportunity

Another comment was that gas turbines have not been designated as a source category after notice and opportunity for a public hearing as set forth in Section 111(f)(8).

Section 111(g)(8) requires EPA to offer an opportunity for a public hearing in proposing, among other things, the Section 111 priority list. It does not require a public hearing in conjunction with the establishment of a specific new source performance standard. Section 307 of the Clean Air Act requires an opportunity for a public hearing but only if an NSPS were proposed after November 5, 1977. Standards for gas turbines were proposed on October 3, 1977. Again, it would be contrary to the intent of the Clean Air Act, as discussed above, to stop the NSPS program until the priority list is proposed and a public hearing held.

Requirement for a Percentage Reduction in Emissions

The meaning of "standard of performance" has changed as set forth in Section 111 according to several commenters. It was pointed out that the requirement of achieving a percentage reduction in emissions has been included in Section 111.

These commenters have apparently misconstrued the gas turbine standard and Section 111, as amended, to suggest that gas turbines designed to comply with the proposed standards would later have to be redesigned to meet a future gas turbine standard that will include a requirement to achieve a percentage reduction in NO_x emissions. It is not clear if Section 111 requires development of standards calling for a percentage reduction in emissions from all fossil-fuel-fired stationary sources; the legislative history of this provision deals only with utility power plant boilers. The commenters' impression that gas turbines designed to meet the promulgated standards would have to be redesigned to meet a future standard that will include a requirement to achieve a percentage reduction in NO_x emission is incorrect. Any such future standard would apply only to gas turbines constructed, modified, or reconstructed after the date of proposal of the future standards.

Conflicting Definitions

One commenter maintained that conflict exists between definitions in the Clean Air Act as amended August 7, 1977, and definitions in the General Provisions of Part 60 which apply to all standards of performance.

The conflict specifically mentioned is in the definition of "standard" or "standard of performance." However, the definition is quite general and is consistent with the 1977 amendments.

2.8 TEST METHODS AND MONITORING

Excessive Monitoring Requirements

A large number of commenters objected to the amount of monitoring required. The proposed standards called for continuous monitoring of fuel consumption and water/fuel ratio, and daily monitoring of sulfur content, nitrogen content, and lower heating value (LHV) of the fuel. The commenters were generally in favor of less frequent periodic monitoring.

The comments with respect to daily monitoring of sulfur and nitrogen content and lower heating value of fuel seem reasonable. Therefore, the standard has been changed to permit determination of these quantities only when a fresh supply of fuel is added to the gas turbine fuel storage facilities. However, in those cases in which gas turbines are fueled from a pipeline transport system without intermediate storage, daily monitoring is still required by the standard unless the owner or operator can show that the composition of the fuel does not fluctuate from day to day. If this is the case, then the owner or operator may submit a custom schedule outlining the time interval for monitoring of fuel sulfur, nitrogen and lower heating value. These custom schedules must be substantiated by data and approved by the Administrator on a case-by-case basis.

Continuous monitoring of water-to-fuel ratio and fuel consumption is retained in the standards. These parameters are readily measured by existing techniques. Even in the case of turbines operated infrequently or remotely, automatic recording techniques are available. Data can be recorded and retrieved for documentation purposes without unreasonable extra manpower application. In any case, such devices would likely be installed for operational purposes.

In addition to objecting to the frequency of monitoring, several commenters maintained that the gas turbine standard should allow fuel analysis by the fuel vendor, since vendors are generally equipped and staffed for such analyses on a routine basis. The commenters pointed out that parameters such as sulfur and nitrogen content and LHV require laboratory equipment and skilled laboratory personnel. Such facilities and personnel are not generally a part of gas turbine installations, and their establishment to meet the requirements of the gas turbine standards would be uneconomical.

There is nothing in the gas turbine standards that specifically requires an owner/operator to have the required analyses performed by himself or his own personnel. Analysis required to meet the monitoring requirements of the standard may be accomplished by anyone, so long as the methods used comply with applicable parts of the standards. This means an owner/operator may contract such analyses to qualified contractors or obtain such services from his fuel supplier if he so desires. The gas turbine standard has been changed to clarify this point.

Acceptability of Manufacturers' Test in Lieu of Performance Tests

Several commenters stated that the regulation should be clarified to allow the performance test to be performed by the manufacturer in lieu of the owner/operator. These commenters viewed site testing procedures as unnecessarily difficult, costly, and of questionable reliability. To simplify verification of compliance with standards and to reduce cost to users, to the government, and to manufacturers, the recommendation was made that each gas turbine model be performance tested at the manufacturer's site. The commenters maintained that gas turbines should not be required to undergo a performance test at the owner/operator's site if they have been shown to comply with the standard by the manufacturer.

Section 111 of the Clean Air Act is not flexible enough to permit the use of a formal certification program such as that described by the commenter.

Responsibility for complying with the standard ultimately rests with the owner/operator, not with manufacturers. Thus, the gas turbine standard does not formally include such a procedure for determining compliance. Section 60.8 of the General Provisions, however, is applicable to all standards of performance, and allows the use of approaches other than performance tests on a case-by-case basis to determine compliance, if the alternate approach demonstrates to the Administrator's satisfaction that the facility is in compliance with the applicable standard. Consequently, manufacturers' tests will be considered, on a case-by-case basis, in lieu of performance tests at the owner/operator's site to demonstrate compliance with the standard of performance for stationary gas turbines. For a manufacturer's test to be acceptable in lieu of a performance test, however, as a minimum the operating conditions of the gas turbine at the installation site would have to be shown to be similar to those during the manufacturer's test. In addition, this procedure will not preclude the Administrator from requiring a performance test at any time to demonstrate compliance with the standard. It thus remains the ultimate responsibility of the owner/operator to comply with the gas turbines standard.

Sampling Methodology--Method 20

Numerous comments were received regarding the sampling methodology (Method 20). Two comments were received stating that the effect of a moisture trap on NO and NO_2 sample concentrations should be studied and specified in the method.

There is no indication that NO is removed from sample gas by contact with condensed moisture. NO_2 will be absorbed in condensed moisture, especially if direct contact is allowed. NO_2 makes up about 2 to 3 percent of the total NO_x gas concentration under peak load conditions of gas turbine operation. Therefore, the maximum effect on the final concentration due to NO_2 loss is only a negative 2 to 3 percent bias under these conditions.

An NO_2 to NO converter has been included in Reference Method 20 for test conditions which produce significant proportions of NO_2, i.e., more than 5 percent of the total NO_x. The converter is placed upstream of the moisture trap in the sample train to minimize the effect of NO_2 removal in the moisture trap. In addition, the design of an acceptable moisture trap is specified in Reference Method 20 and emphasizes the need to minimize direct contact of the sample gas with the condensate.

Another commenter pointed out that calibration gas is introduced downstream from the filter, whereas the gas sample is not. The commenter points out that absorption of NO_x on the filter and leakage at the filter will reduce the concentration of NO_x in the sample analysis.

Based on the nonreactive properties of NO, the loss of NO on the filter is expected to be negligible. Any leakage that occurs at the filter or any component of the sample conditioning equipment is accounted for by the O_2 correction in the calculation of emissions. Reference Method 20 has been revised, however, to reposition the calibration valve assembly upstream of all sample conditioning equipment in order to allow checks of the NO_2 to NO converter and to ensure that any losses that do occur are detected.

One commenter expressed the opinion that sample transport lines from the probe to the analyzer should be reduced to produce response times of

30 seconds or less in order to minimize any reaction of NO_x with the sampling system.

EPA agrees that the sample transport time should be minimized and has included a specification for this factor in the method.

Objections were expressed by another commenter regarding the number of sampling points. The commenter maintained that the necessity for such a large number of cross-sectional sampling points at the sampling site should be reviewed in light of the fact that this is gaseous sampling as opposed to particulate sampling.

In the exhaust from gas turbines, stratification of NO_x concentrations is likely and must be taken into account during the performance test. The requirement to use the specified 8 sample points is not unrealistic, nor is it unduly restrictive.

One commenter felt that the reference method for oxygen concentration determinations should be the paramagnetic analyzer method.

EPA does not normally specify a particular type of test equipment, but instead, requires the test equipment to meet minimum operational requirements and calibration specifications. In this case, several types of O_2 analyzers can be acceptable for the Reference Method.

One writer requested allowance for use of equivalent analytical methodology for measuring pollutants, without Administrator approval, as agreed upon by regional EPA or state authorities and the company operating the turbine. This is already allowed. As in many cases, the EPA Administrator is represented by the EPA Regional office. The Office of Air Quality Planning and Standards represents the EPA Administrator only in those cases where alternative methods are approved for nationwide use.

Another writer commented that the NO_x analyzer range specification should allow a higher-than-120-ppm range.

The 120-ppm range was chosen to maintain a satisfactory degree of resolution in the range of emission measurements and to have the measurements at the level of the standard at mid-scale. Because of adjustments to the emission standard allowed in the revised regulation, the 120-ppm span level may be exceeded and the gas turbine may still be in compliance. Reference Method 20 has been revised to specify calibration gas levels and measurement ranges based on span levels specified in the regulation. The span level is chosen to allow the accuracy and resolution required of the method and to allow measurement of emissions over the expected range.

One commenter indicated that traceability should be insured by using standard reference gases available from NBS and by using a protocol currently being developed by Environmental Monitoring Systems Laboratory, EPA. (GT-29)

At this time there is no traceability protocol published for source level gas cylinders. Reference Method 20 provides for inclusion of such procedures when they become available.

One criticism was that Method 7 for analysis of NO_x calibration gas mixtures should not be the recommended method since it has been shown to be extremely variable.

EPA recognizes that Reference Method 7 produces variable results at low NO_x concentrations, but careful laboratory practices and proper administered sampling can produce acceptable results. Detailed procedures for establishing cylinder concentrations have been developed to insure reliable results.

According to one commenter, measurement system calibration is not adequately precise. The nitrogen oxides analyzer should be spanned at 90 percent (± 10 percent) of the expected measured NO_x value.

To set the span value at this high concentration would prohibit measurement of excess emissions if such occurred. The calibration values and procedures required in Reference Method 20 provide adequate analysis precision and accuracy for the emissions determination.

One commenter maintained that Method 20 does not guarantee that the sample is representative; thus it does not assure that there have been no errors. The commenter suggests the use of a carbon balance to assure a representative sample. In the suggested technique, the following measurements are required: fuel input rate, fuel analysis, effluent volumetric flow rate, effluent hydrocarbons, CO_2, and CO.

The carbon balance technique is a good method for providing representative flow rate and carbon measurements. These determinations are not required for the gas turbine NO_x standard. Representative NO_x measurements are handled in Reference Method 20 by the requirement of a suitable number of sample points. Data from many sources indicate that stratification problems in stacks can be corrected by multi-point sampling and proper positioning of the probe.

Two commenters felt that the accuracy of the method has not been adequately specified.

The accuracy of Reference Method 20 is dependent on the proper introduction and certification of calibration gases and proper sample collection. Both of these criteria are addressed in Reference Method 20. If the method is followed correctly, accuracy should be on the order of reproducibility of the method.

Alternative Sulfur Measurement Method

One commenter suggested that alternative methods for determining sulfur content of the fuel should be allowed. The writer proposed that several alternative methods would serve the purpose as well as ASTM D2880-71, which was specified in the proposed standard.

The validity of using alternative test methods is recognized. In fact, there are provisions made for alternative methods in the General Provisions. Thus, subject to prior approval on a case-by-case basis, alternative methods of measurement are acceptable.

TABLE 2-1
LIST OF COMMENTERS ON THE PROPOSED STANDARDS OF PERFORMANCE
FOR STATIONARY GAS TURBINES

Commenter	Affiliation
GT-1	Richard F. Richter Assistant Administration - Electric U. S. Department of Agriculture Rural Electrification Administration Washington, D. C. 20250
GT-2	J. M. Otts, Jr., Vice-President Gulf Energy & Minerals Company Post Office Box 2100 Houston, Texas 77001
GT-3	Charles W. Whitmore State Coordinator, Air Support Air & Hazardous Materials Division Region VII Environmental Protection Agency Research Triangle Park, North Carolina 27711
GT-4	M. F. Tyndall, Project Manager Catalytic, Incorporated Centre Square West 1500 Market Street Philadelphia, Pennsylvania 19102
GT-5	J. V. Day, Manager Environmental Affairs Kaiser Aluminum & Chemical Corporation 300 Lakeside Drive Oakland, California 94643
GT-6	John M. Vaught, Chairman ASME Gas Turbine Division Combustion Research & Development Detroit Diesel Allison Post Office Box 894 Indianapolis, Indiana 46206

Commenter	Affiliation
GT-7	Don E. Gerard, General Manager Board of Public Utilities City of McPherson, Kansas 67460
GT-8	D. McKnight Assistant Chief Development Engineer Rolls-Royce Limited Post Office Box 72 Ansty, Coventry CV7 9JR
GT-9	D. R. Plumley General Electric One River Road Schenectady, New York 12345
GT-10	James L. Grahl Basin Electric Power Cooperative 1717 East Interstate Avenue Bismarck, North Dakota 58501
GT-11	Perry G. Brittain, President Texas Utilities Services, Incorporated 2001 Bryan Tower Dallas, Texas 75201
GT-12	K. A. Krumwiede Southern California Edison Company Post Office Box 800 Rosemead, California 91770
GT-13	J. Thomas Via, Jr., Vice-President Tucson Gas & Electric Company Post Office Box 711 Tucson, Arizona 85702
GT-14	S. David Childers, Attorney Law Department Salt River Project Post Office Box 1980 Phoenix, Arizona 85001

Comments	Affiliation
GT-15	R. J. Moolenaar Environmental Sciences Research Dow Chemical U. S. A. Midland, Michigan 48640
GT-16	W. J. Coppoc, Vice-President Environmental Protection Texaco Incorporated Post Office Box 509 Beacon, New York 12508
GT-17	Raymond E. Kary, Ph.D., Manager Environmental Management Department Arizona Public Service Company Post Office Box 21666 Phoenix, Arizona 85036
GT-18	William S. LaLonde, III, P.E., President National Energy Leasing Company Elizabeth Plaza Elizabeth, New Jersey 07207
GT-19	H. D. Belknap, Jr., Assistant Counsel Southern California Edison Company Post Office Box 800 Rosemead, California 91770
GT-20	O. Morris Sievert, President Solar Turbines International Post Office Box 80966 San Diego, California 92138
GT-21	James A. Shissias, General Manager Environmental Affairs Public Service Electric & Gas Company 80 Park Place Newark, New Jersey 07101
GT-22	George Opdyke, Jr., Manager Combustor Section Avco Lycoming Divsion 550 South Main Street Stratford, Connecticut 06497

Comments	Affiliation
GT-23	W. H. Axtman, Assistant Executive Director American Boiler Manufacturers Association Suite 317 - AM Building 1500 Wilson Boulevard Arlington, Virginia 22209
GT-24	Douglas W. Meaker, Technical Director Reigel Products Corporation Subsidiary of James River Corporation Milford, New Jersey 08848
GT-25	S. J. Thomson, P. E. 1174 Gleneagles Terrace Costa Mesa, California 92627
GT-26	I. H. Gilman, General Manager Environmental Affairs Chevron U. S. A. Incorporated Post Office Box 3069 San Francisco, California 94119
GT-27	W. Samuel Tucker, Jr., Manager Environmental Affairs Florida Power & Light Miami, Florida 33101
GT-28	John M. Daniel, Jr., P. E. Assistant Executive Director Commonwealth of Virginia State Air Pollution Control Board Room 1106 - Ninth Street Office Building Richmond, Virginia 23219
GT-29	John B. Clements, Chief (MD-77) Quality Assurance Branch Environmental Monitoring and Support Laboratory Environmental Protection Agency Research Triangle Park, North Carolina 27711
GT-30	John G. Farley, Jr., Manager Environmental Licensing Department Southern Company Services, Incorporated Post Office Box 2625 Birmingham, Alabama 35202

Commenter	Affiliation
GT-31	B. E. Davis, System Engineer Environmental Regulation Duke Power Company Steam Production Department Post Office Box 2176 Charlotte, North Carolina 28242
GT-32	L. A. McReynolds, Manager Environmental and Consumer Protection Phillips Petroleum Company Bartlesville, Oklahoma 74004
GT-33	F. D. Bess, Manager Regulatory Coordination and Information Union Carbide Corporation Post Office Box 8361 South Charleston, West Virginia 25303
GT-34	Robert A. McKnight Chief Environmental Engineer Inianapolis Power & Light Indianapolis, Indiana 46206
GT-35	John R. Thorpe, Manager Environmental Affairs GPU Service Corporation 260 Cherry Hill Road Parsippany, New Jersey 07054
GT-36	Jack M. Heineman, Advisor Environmental Quality Federal Energy Regulatory Commission Washington, D. C. 20426
GT-37	Charles Custard, Director Office of Environmental Affairs Department of Health, Education & Welfare Office of the Secretary Washington, D. C. 20201

Commenter	Affiliation
GT-38	J. B. Miller, President Rio Blanco Oil Shale Project 9725 E. Hampden Avenue Denver, Colorado 80231
GT-39	P. W. Howe, Vice-President Technical Services Carolina Power & Light Company Post Office Box 1551 Raleigh, North Carolina 27602
GT-40	James L. Grahl, General Manager Basin Electric Power Cooperative 1717 East Interstate Avenue Bismarck, North Dakota 58501
GT-41	R. M. Robinson, Coordinator Environmental Conservation Continental Oil Company Houston, Texas 77001
GT-42	M. C. Steele, Assistant Director Engineering Airesearch Manufacturing Company of Arizona Post Office Box 5217 Phoenix, Arizona 85010
GT-43	M. W. Beard, P. E. 2529 Cardillo Avenue Hacienda Heights, California 91745
GT-44	J. Albert Curran Vice-President and Secretary C F Braun & Company, Engineers Alhambra, California 91802

Commenter	Affiliation
GT-45	Douglas L. Lesher, Chief Permit Section Division of Abatement & Compliance Bureau of Air Quality and Noise Control Commonwealth of Pennsylvania Department of Environmental Resources Post Office Box 2063 Harrisburg, Pennsylvania 17120
GT-46	H. D. Ege, Jr., P. E. Burns & McDonnell Engineers-Architects-Consultants Post Office Box 173 Kansas City, Missouri 64141
GT-47	Larry E. Meierotto Deputy Assistant Secretary United States Department of the Interior Washington, D. C. 20240
GT-48	R. J. Corbeil, Manager Environmental Affairs Southern California Gas Company Box 3249 - Terminal Annex Los Angeles, California 90051
GT-49	W. B. Read, President The Oil Center 2150 Westbank Expressway Harvey, Louisiana 70058
GT-50	W. D. Cleaver, Assistant Vice-President Northern Illinois Gas Post Office Box 190 Aurora, Illinois 60507
GT-51	R. C. Jackson, Chairman Pipeline Research Committee American Gas Association 1515 Wilson Boulevard Arlington, Virginia 22209

Commenter	Affiliation
GT-52	R. W. Hospodarec, P. E. 3652 Pine street Irvine, California 92714
GT-53	William T. Turner, Jr., Vice-President Engineering Texas Gas Transmission 3800 Frederica Street Owensboro, Kentucky 52301
GT-54	D. R. Plumley General Electric Company One River Road Schenectady, New York 12345
GT-55	Lawrence J. Ogden, Director Construction & Operations Interstate Natural Gas Association 1660 L Street Northwest Washington, D. C. 20035
GT-56	Rodger L. Staha, Ph.D. Air Quality Advisor - Environmental Quality Pacific Gas and Electric Company 77 Beale Street San Francisco, California 94106
GT-57	Walfred E. Hensala, P. E., Manager Environmental Affairs Post office Box 1526 Salt Lake City, Utah 84110
GT-58	John M. Craig, Director Environmental Affairs El Paso Natural Gas Company Post Office Box 1492 El Paso, Texas 79978
GT-59	Albert C. Clark Vice-President/Technical Director Manufacturing Chemists Association 1825 Connecticut Avenue, Northwest Washington, D. C. 20009

Commenter	Affiliation
GT-60	T. H. Rhodes, Manager Environmental Conservation Exxon Chemical Company U. S. A. Post Office Box 3272 Houston, Texas 77001
GT-61	Thomas R. Hanna, Supervisor Air Quality Control - State of Alaska Department of Environmental Conservation Pouch O Juneau, Alaska 99811
GT-62	D. R. Jones, manager Longe Range Development Generation Systems Division Westinghouse Electric Corporation Lester Branch Box 9175 Philadelphia, Pennsylvania 19113
GT-63	H. H. Meredith, Jr., Coordinator Public Affairs Department Environmental Conservation Exxon Company U. S. A. Post Office Box 2180 Houston, Texas 77001
GT-64	D. G. Assard, Director Engineering United Technologies Power Systems Division 1690 New Britain Avenue Farmington, Connecticut 06032
GT-65	T. M. Fisher, Director Automotive Emission Control Enviromental Activities Staff General Motors Corporation Warren, Michigan 48090
GT-66	Robert W. Welch, Jr., Vice-President Environmental Affairs Columbia Gas Systems Service Corporation 20 Montchanin Road Wilmington, Delaware 19807

Commenter	Affiliation
GT-67	Donald W. Moon Senior Environmental Analyst Salt River Project Post Office Box 1980 Phoenix, Arizona 85001
GT-68	R. H. Gaylord, Senior Engineer Advanced Projects Engineering Brown Boveri Turbomachinery, Incorporated 711 Anderson Avenue North Saint Cloud, Minnesota 56301
GT-69	Howard A. Koch, Manager Atlantic Richfield Company North American Producing Division Dallas, Texas 52311
GT-70	C. W. Kern, Supervisor Environmental Planning Northern Indiana Public Service Company 5265 Hohman Avenue Hammond, Indiana 46325
GT-71	V. Rock Grundman, Jr., Counsel Government/Business Affairs Dresser Industries, Incorporated Dresser Building - Elm at Akard Dallas, Texas 75221
GT-72	F. R. Fisher, Manager Environmental Protection Alyeska Pipeline Service Company Post office Box 4-Z Anchorage, Alaska 99509
GT-73	W. H. Pennington, Director Office of National Environmental Policy Act Coordination Department of Energy Washington, D. C. 20545

Commenter	Affiliation
GT-74	W. M. Hathaway, Vice-President Process and Environmental Engineering Flour Engineers and Constructors, Inc. Post Office Box 11977 Santa Ana, California 92711
GT-75	C. H. Golliher, Supervisor Environmental Services Division Iowa-Illinois Gas & Electric Post Office Box 4350 Davenport, Iowa 52808
GT-76	John J. Kearney, Senior Vice-President Edison Electric Institute 1140 Connecticut Avenue, N. W. Washington, D. C. 20036
GT-77	William W. Hopkins, Executive Director Alaska Oil and Gas Association 505 West Northern Lights Boulevard Suite 219 Anchorage, Alaska 99503
GT-78	John F. Vogt, Jr., Vice-President Engineering and Operations Middle South Services, Incorporated Box 61000 New Orleans, Louisiana 70161

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-450/2-77-017b	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Standards Support and Environmental Impact Statement, Volume II: Promulgated Standards of Performance for Stationary Gas Turbines		5. REPORT DATE September 1979 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S)		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Standards Development Branch Emission Standards and Engineering Division Research Triangle Park, N. C. 27711		10. PROGRAM ELEMENT NO. 11. CONTRACT/GRANT NO.
12. SPONSORING AGENCY NAME AND ADDRESS OAA for Air Quality Planning and Standards Office of Air and Waste Management U.S. Environmental Protection Agency Research Triangle Park, N. C. 27711		13. TYPE OF REPORT AND PERIOD COVERED 14. SPONSORING AGENCY CODE EPA/200/04

15. SUPPLEMENTARY NOTES Volume I discussed the proposed standards and the resulting environmental and economic effects. Volume II contains a summary of public comments, EPA responses and a discussion of differences between the proposed and promulgated standards.

16. ABSTRACT

Standards of performance to control nitrogen oxides and sulfur dioxide emissions from new, modified and reconstructed stationary gas turbines in the U.S. are being promulgated under section 111 of the Clean Air Act. This document contains information on the public comments made after proposal, EPA responses and differences between the proposed and promulgated standards.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Gas Turbines Air pollution control equipment Standards of Performance	Air pollution control sulfur dioxides Nitrogen oxides Water injection	

18. DISTRIBUTION STATEMENT Unlimited - Available to the public free of charge from: U.S. EPA Library (MD-35) Research Triangle Park, N. C. 27711	19. SECURITY CLASS *(This Report)* unclassified 20. SECURITY CLASS *(This page)* unclassified	21. NO. OF PAGES 60 22. PRICE

EPA Form 2220-1 (Rev. 4-77) PREVIOUS EDITION IS OBSOLETE