

DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee	
To: _____	Loctn.: _____
To: <i>Steve Smallwood</i>	Loctn.: _____
To: _____	Loctn.: _____
From: <i>Victoria Martinez</i>	Date: <i>8-17-78</i>

TO: Steve Smallwood, Albert Townsend
Robert Kappelmann and Frank Darabi

FROM: J. P. Subramani *JPSubramani*

DATE: August 16, 1978

SUBJECT: BACT Application for Four Florida Power
Corporation Gas Turbines, Suwannee River Plant
Site, Suwannee County

Thank you for contributing your expertise to the study group for the above referenced BACT Determination. After carefully examining your recommendation and those of the other participants in the study group, the attached determination was made.

JPS/VM/es

Attachment

[6506-01]

ENVIRONMENTAL PROTECTION
AGENCY

[40 CFR Part 60]

[FRL 777-8]

STATIONARY GAS TURBINES

Standards of Performance for New
Stationary SourcesAGENCY: Environmental Protection
Agency.

ACTION: Proposed rule.

SUMMARY: The proposed standards would limit emissions of nitrogen oxides and sulfur dioxide from new, modified and reconstructed stationary gas turbines to 75 ppm and 150 ppm, respectively. A new reference method for determining the concentration of nitrogen oxides, sulfur dioxide and oxygen in the exhaust gases from stationary gas turbines is also proposed. The standards implement the Clean Air Act and are based on the Administrator's determination that stationary gas turbine emissions contribute significantly to air pollution. The intended effect is to require new, modified and reconstructed stationary gas turbines to use the best demonstrated system of emission reduction.

DATES: Comments must be received on or before December 2, 1977.

ADDRESSES: Comments should be submitted, preferably in triplicate, to the Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, N.C. 27711. Attention: Mr. Don R. Goodwin.

The Standards Support and Environmental Impact Statement (SSEIS) containing the data and information upon which the proposed standards are based may be obtained from the Public Information Center (PM-315), U.S. Environmental Protection Agency, Washington, D.C. 20460 (specify "Standards Support and Environmental Impact Statement, Volume 1: Proposed Standards of Performance for Stationary Gas Turbines").

The SSEIS and 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, N.C. 27711, telephone No. 919-541-5271.

SUPPLEMENTARY INFORMATION:

PROPOSED STANDARDS

The proposed standards would apply to all new, modified and reconstructed stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (about 1,000 horsepower). The standards would apply to simple and regenerative cycle gas turbines and to the gas turbine portion of a

combined cycle steam/electric generating system.

The proposed standards would limit the concentration of nitrogen oxides (NO_x) in the exhaust gases from stationary gas turbines to 0.0075 percent by volume (75 ppm) at 15 percent oxygen on a dry basis. This emission limit would be adjusted upward for turbines with thermal efficiencies greater than 25 percent and upward for turbines burning fuels with a nitrogen content greater than 0.015 percent by weight.

The proposed standard would be referenced to International Standard Organization (ISO) standard day conditions of 288 degrees Kelvin, 60 percent relative humidity, and 101.3 kilopascals (1 atmosphere) pressure. Measured NO_x emission levels, therefore, would be adjusted to ISO reference conditions by use of an ambient condition correction factor included in the standard or by a custom ambient condition correction factor developed by the gas turbine manufacturer, owner, or operator and approved for use by EPA. Manufacturers, owners, or operators electing to develop custom ambient condition correction factors, however, would be required to develop such factors in terms of the following variables: combustor inlet pressure, ambient air pressure, ambient air humidity, and ambient air temperature. All correction factors would have to be substantiated with data and approved for use by the Administrator before they could be used for determining compliance with the proposed standard.

Stationary gas turbines with a heat input at peak load from 10.7 to, and including, 107.2 gigajoules per hour would be exempt from the NO_x emission limit for five years from the date of this proposal. Emergency-standby gas turbines, military gas turbines and firefighting gas turbines would be exempt permanently from the NO_x emission limit. In addition, stationary gas turbines using wet controls would be exempt temporarily from the NO_x emission limit during those periods when ice fog created by the gas turbine was deemed by the owner or operator of the gas turbine to present a traffic hazard. None of the exemptions mentioned in this paragraph would apply to the SO₂ emission limit.

The proposed standards would limit the SO₂ concentration in the exhaust gases from stationary gas turbines to 0.015 percent by volume (150 ppm) corrected to 15 percent oxygen on a dry basis, or would limit the sulfur content of the fuel used by any stationary gas turbine to 0.8 percent by weight.

SUMMARY OF ENVIRONMENTAL AND
ECONOMIC IMPACTS

The proposed standards would reduce NO_x emissions from stationary gas turbines by about 70 percent. Based on industry growth projections, by 1982 a reduction in national NO_x emissions of about 190,000 tons per year would be realized. By 1987, the reduction in national NO_x emissions would reach about 400,000 tons per year.

The adverse water pollution impact of the proposed standards would be minimal. The quantity of water or steam required for injection into the gas turbines to reduce NO_x emission would be small, less than 5 percent of the water consumed by a comparable size steam/electric power plant using cooling towers.

The solid waste impact of the proposed standards would be negligible. There would also be no adverse noise impact resulting from the proposed standards.

The energy impact of the proposed standards would be small. Gas turbine fuel consumption would be increased from 0 to 5 percent, depending largely on the rate of water injection required to comply with the proposed NO_x standard. There would be no energy impact associated with the proposed SO₂ standard. Few turbines will require the high water injection rates (about 1:1 water-to-fuel ratios) which result in a 5 percent fuel penalty. Assuming that all stationary gas turbines subject to the proposed NO_x standard would require a 1:1 water-to-fuel ratio, the fifth year (1982) energy impact of the standard on large stationary gas turbines would be an increase in fuel consumption of about 5,500 barrels of fuel oil per day. The fifth-year (1987) energy impact of the NO_x standard on small stationary gas turbines would be an increase in fuel consumption of about 7,000 barrels of fuel oil per day. This is equivalent to an increase in projected 1982 and 1987 national crude oil consumption of less than 0.03 percent. These estimates are based on assumptions which yield the greatest energy impacts and actual impacts are expected to be much lower.

The economic impact of the proposed standards is considered to be reasonable. The proposed standards would increase the capital costs or purchase price of a gas turbine for most installations by about 1 to 4 percent. For offshore applications, however, such as oil and gas drilling platforms, the increase could be as much as 7 percent. The annualized costs for a gas turbine in all applications would be increased by about 1 to 4 percent, with the largest application, utilities, realizing less than a 2 percent increase.

The proposed standards would increase the total capital investment requirements for all users of large stationary gas turbines by about 36 million dollars by 1982. For the period 1982 through 1987, the standards would increase the capital investment requirements for all users of both large and small stationary gas turbines by about 67 million dollars. Total annualized costs would be increased by about 11 million dollars in 1982 and by about 30 million dollars in 1987. These impacts would result in price increases for the end products or services provided by industrial and commercial users of stationary gas turbines ranging from less than 0.01 percent in the petroleum refining industry to about 0.1 percent in the electric utility industry.

The criteria for an action to be considered major, thereby requiring development of an Economic Impact Analysis (EIA) are: (1) an increase in the fifth-year annualized costs of 100 million dollars, (2) a major product price increase of 5 percent, or (3) an increase in national energy consumption of 25,000 barrels of fuel oil per day. The impacts resulting from the proposed standards would not exceed these criteria, except possibly for offshore applications, where the proposed standards could increase the price of a gas turbine by about 7 percent. Most gas turbines used on offshore oil and gas drilling platforms, however, are likely to have a heat input at peak capacity of less than 107.2 gigajoules per hour (about 10,000 horsepower). Consequently, they would be considered small gas turbines and would be exempt from the standards for five years. In any event, stationary gas turbines sold for offshore applications constitute such a small percentage (estimated at less than 3 percent) of the overall market for gas turbines that they are not considered a major product within the intent of the 5 percent major product price increase criteria for preparation of an EIA. Consequently, the proposed standards would not constitute a major action and no EIA has been prepared.

RATIONALE

SELECTION OF SOURCE FOR CONTROL

Assuming existing levels of emission controls, national NO_x emissions from stationary sources are projected to increase by about 65 percent by 1985. Applying best technology to all new sources would reduce this increase to about 25 percent, but would not prevent it from occurring. This unavoidable increase in NO_x emissions is attributable largely to the fact that few of the NO_x emission control techniques currently available can achieve large reductions in NO_x emissions. Consequently, EPA has assigned a high priority to the development of standards of performance for major NO_x emission sources wherever significant reductions in NO_x emissions can be achieved.

Several studies sponsored by EPA have ranked stationary gas turbines as major controllable sources of NO_x emissions. One study conducted by the Aero-therm Division of Acurex Corporation estimated that oil-fired and gas-fired stationary gas turbines accounted for 2.5 percent of the total NO_x emissions from stationary sources in the U.S. in 1972. This same study ranked gas-fired turbines as sixteenth and oil-fired gas turbines as twenty-third in a priority listing of 137 controllable stationary sources NO_x emissions.

In another study the Research Corp. New England (TRC) determined the impact which standards of performance would have on nationwide emissions of particulates, NO_x, SO₂, HC (hydrocarbons), and CO (carbon monoxide) from stationary sources. Sources were then ranked according to the impact a stand-

ard promulgated in 1975 would have on emissions in 1985. This ranking placed gas turbines first on a list of 40 stationary NO_x emission sources and eighth on a list of 41 stationary SO₂ emission sources.

In 1974, 90 percent of all domestic stationary gas turbine capacity was sold to the electric utility market, primarily for use as peaking units. It is expected that this large percentage of sales to utilities will continue in the future due to the many advantages of gas turbines as peaking units. In addition, gas turbine peaking units are often located in large urban centers where power demands are greatest and pollution problems are often most severe.

Stationary gas turbines, therefore, are significant contributors to total nationwide emissions of NO_x. They are ranked high on the various listings of sources for which standards of performance should be developed. In addition, the turbines coupled with the probability that many gas turbines will be installed near large urban centers underscores the need for standards of performance for stationary gas turbines. Consequently, stationary gas turbines were selected for development of standards of performance.

SELECTION OF POLLUTANTS

The pollutants emitted from stationary gas turbines are particulates, NO_x, SO₂, CO and HC. Combustor modifications (dry control) and water injection (wet control) are demonstrated techniques for reducing NO_x emissions at reasonable cost and depending on specific emission level selected, could reduce NO_x emissions by up to 190,000 tons per year in 1982. This is a significant decrease in total nationwide NO_x emissions. For these reasons, NO_x emissions from stationary gas turbines were selected for control by standards of performance.

SO₂ emissions from stationary gas turbines depend on the sulfur content of the fuel since nearly 100 percent of the fuel sulfur is converted to SO₂ during the combustion process. Due to the high volumes of exhaust gases, the cost of flue gas desulfurization (FGD) to control SO₂ emissions from stationary gas turbines is considered unreasonable. Control of SO₂ emissions, therefore, would require combustion of low sulfur fuels rather than the application of FGD. Selection of low sulfur fuels, however, is considered reasonable. Since gas turbines are a major source of SO₂ emissions and firing low sulfur fuels is considered an economically feasible control technique, SO₂ emissions from stationary gas turbines were selected for control by standards of performance.

HC and CO emissions from stationary gas turbines operating at peak load are relatively low because the higher the percentage of peak load at which a turbine operates, the more efficient the combustion of the fuel. Gas turbines normally operate at 80 to 100 percent of peak load with HC emissions averaging less than 50 ppm and CO emissions averaging less than 500 ppm at 15 percent oxygen. HC

and CO emissions from stationary gas turbines, therefore, were not selected for control by standards of performance.

Particulate emissions from stationary gas turbines depend on the ash content of the fuel and are minimal. Consequently, particulate emissions from stationary gas turbines were not selected for control by standards of performance.

SELECTION OF AFFECTED FACILITIES

Stationary gas turbines can be used in three different configurations: simple cycle, regenerative cycle, and combined cycle. All of these configurations emit NO_x and SO₂, and all can be controlled for NO_x emissions by water injection or dry controls and for SO₂ by the firing of low sulfur fuels. Consequently, simple cycle gas turbines, regenerative cycle gas turbines and the gas turbine portion of combined cycle steam/electric generating systems were selected as the affected facilities for standards of performance limiting NO_x and SO₂ emissions.

Gas turbines can burn either liquid or gaseous fuels. Dry and wet control techniques for the control of NO_x can be applied to gas turbines regardless of the type of fuel burned. Similarly, the firing of low sulfur fuel for the control of SO₂ emissions can be applied to gas turbines regardless of the type of fuel burned. EPA recognizes the fact that at the present time gas turbines firing coal-derived fuels probably could not meet the standards of performance. Coal-derived fuels, however, will not be available in commercial quantities to gas turbines for at least ten years and EPA feels that by that time the emission control technology for clean firing of these fuels could be developed. Consequently, gas turbines burning all types of fuels are selected as affected facilities for standards of performance.

For many applications up to about 10,000 hp stationary gas turbines compete with internal combustion engines. A standard of performance on one of these industries and not the other would tend to give the non-regulated industry a competitive advantage to some extent.

Currently, standards of performance are being developed for stationary internal combustion engines. Although relatively few internal combustion engines of greater than 1,000 hp are produced, these engines are responsible for 75 percent of the total NO_x emissions from stationary internal combustion engines. Under 1,000 hp, however, the number of internal combustion engines produced increases tremendously and enforcement of standards of performance would not be feasible in the absence of a certification program similar to that for automobiles. Since the Clean Air Act does not permit standards of performance to be enforced by a certification program, a lower size cutoff of 1,000 hp for standards of performance for stationary internal combustion engines is considered appropriate. Consequently, to be consistent a lower size cutoff of 10.7 gigajoules per hour heat input (about 1,000 hp) is selected for standards of performance for

stationary gas turbines. Gas turbines less than 10.7 gigajoules per hour heat input (about 1,000 hp) account for less than 10 percent of the total NO_x emissions from stationary gas turbines. Below this cutoff the standards limiting NO_x and SO_x emissions would not apply.

Some stationary gas turbines are operated as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation. This type of gas turbine operates infrequently, usually only for checkout and maintenance; therefore, it contributes only a very small amount to total nationwide NO_x emissions. There also could be operational problems with the water injection system due to the long periods of non-operation. Consequently, emergency-standby stationary gas turbines were exempted from standards of performance limiting NO_x emissions.

Stationary gas turbines could contribute to the creation of ice fog, which consists of small ice crystals which are nucleated by airborne particulate. Ice fog occurs at temperatures below -28° C and is a serious problem in only a small portion of the United States, primarily Alaska. Ice fog severely restricts visibility and, since the crystals are long-lived, can plague auto and air traffic for extended periods. The actual impact of water or steam injection into gas turbines on the formation of ice fog is unknown; however, water or steam injection will increase the moisture content of the exhaust gas discharged by gas turbines. Since ice fog occurs only in a small portion of the United States and only under special weather conditions, the impact on air quality due to increased NO_x caused by exempting gas turbines creating ice fog would be minimal. Therefore, gas turbines using water or steam injection for control of NO_x emissions would be exempt from the standards limiting NO_x emissions when ice fog created by the gas turbine is deemed by the owner or operator of the gas turbine to be a traffic hazard.

Stationary gas turbines are sometimes used by the military in combat-type situations. The main advantage of these turbines is their mobility, which would be considerably restricted by a water injection system consisting of either water treatment equipment or a water storage vessel. Restriction of the mobility of these gas turbines could have an adverse effect on national defense; therefore, any military combat-type gas turbine for use in other than a garrison facility is exempt from the standards limiting NO_x emissions.

The possibility of exempting some gas turbines from the standard limiting SO_x emissions was also examined. Except for exempting all turbines of less than 10.7 gigajoules per hour heat input (about 1,000 hp), no exemptions were considered necessary.

SELECTION OF THE BEST SYSTEM OF EMISSION REDUCTION

There are three possible control techniques for reducing NO_x emissions from

stationary gas turbines: wet controls, dry controls, and catalytic exhaust cleanup. Wet controls involve the injection of water or steam into the combustion reaction to reduce peak flame temperatures, thereby reducing NO_x formation. Wet control techniques have been demonstrated on a few large gas turbines (greater than 10,000 hp) used in utility and industrial applications. These installations have had good reliability over long periods of operation. Wet controls, however, have not been applied to small production gas turbines (less than 10,000 hp), although the effectiveness of these techniques for small gas turbines has been demonstrated in laboratory and combustor rig tests. Thus, wet controls can be applied immediately to large stationary gas turbines, but manufacturers estimate that at least three years would be required to incorporate and test wet control techniques on small production gas turbines.

Dry controls consist of operational or design modifications which govern combustion conditions to reduce NO_x formation. Although dry controls have been demonstrated in laboratory and combustor rig tests, manufacturers estimate that up to five years is required for further development, design, test, and incorporation of dry controls on large and small stationary gas turbines.

Catalytic exhaust gas cleanup consists of NO_x reduction by ammonia in the presence of a catalyst. While laboratory tests are very promising, this technique is not demonstrated for stationary gas turbines.

The NO_x emission reduction achievable with wet and dry control techniques clearly favors the development of standards of performance based on wet controls. Reductions in NO_x emissions of more than 70 percent have been demonstrated using wet controls. Dry controls, however, have demonstrated NO_x emission reductions of only about 30 percent.

Standards of performance based on wet controls would reduce national NO_x emissions by about 190,000 tons per year in 1982. In contrast, standards of performance based on dry controls would have no impact on national NO_x emissions in 1982, due to the necessity of allowing a five-year delay to incorporate dry controls on gas turbines. By 1987, standards based on wet controls would reduce national NO_x emissions by about 400,000 tons per year, whereas standards based on dry controls would reduce NO_x emissions by only about 90,000 tons per year. Thus, standards of performance based on wet controls would have a much greater impact on national NO_x emissions than standards based on dry controls.

The water pollution impact of standards based on wet controls would be minimal. Water needed for wet controls may be treated by the same processes used to treat steam boiler make-up water. The quality of the wastewater from this treatment is essentially the same as the influent water except that the concentration of total dissolved solids in the effluent stream is 3 to 4

times that of the influent. In most cases, the effluent may be seweraged directly or returned to the river supplying the water. Where this is not possible, the effluent may be discharged to an evaporation pond. Consequently, the water pollution impact of standards based on wet controls would be minimal.

The quantity of water required by a stationary gas turbine using wet controls is relatively small. The upper limit water-to-fuel ratio of about 1:1 requires only about 5 percent of the quantity of water consumed by a comparable size steam boiler using cooling towers. A water treatment system for five 28 MW stationary gas turbines operating 10 hours per day using a water-to-fuel ratio of 1:1, for example, would treat 125,000 gallons of water and reject about 25,000 gallons of wastewater per day. A steam boiler of comparable size with cooling towers would consume 20 times as much water. In fact, the usage rate of water for wet controls is small enough that the unlikely prospect of having to truck water 50 miles was determined to be economically reasonable as discussed below. Standards based on dry controls, however, would have no impact on water pollution or water supplies.

Standards based on wet controls would have a negligible solid waste impact. Also, there would be no adverse noise impact resulting from standards based on either wet or dry controls.

The potential energy impact of standards based on wet controls is small. Standards based on wet controls could increase the fuel consumption of a gas turbine from 0 to 5 percent, depending on the rate of water injection required to comply with the standard. Few turbines will require the high water injection rates (about 1:1 water-to-fuel ratios) which result in a 5 percent fuel penalty. Assuming, however, that all stationary gas turbines subject to compliance with standards would require a 1:1 water-to-fuel ratio, the energy impact on large stationary gas turbines would be an increase in fuel consumption of about 5500 barrels of fuel oil per day in 1982. The energy impact on small stationary gas turbines would be an increase in fuel consumption of about 7,000 barrels per day of fuel oil in 1987, as a result of the delayed effective date of the proposed standards on small turbines. Each increase represents less than a 0.03 percent increase in projected crude oil consumption in the United States in 1982 and 1987. It should also be recognized that these estimates are based on assumptions which yield the greatest energy impacts. Actual energy impacts are expected to be much lower. The energy impact of standards based on wet controls, therefore, would be minimal. Standards based on dry controls, however, would have no energy impact.

Although wet controls would result in a small adverse impact on gas turbine efficiency, the costs associated with this increased fuel consumption for some applications may be partially offset by an increase in the gas turbine's rated power output capability. Based on manufacturer's estimates, gas turbine based

capacity will be increased by 3 to 4 percent as a result of water injection. In applications where turbines are operated at maximum capacity, such as utility power generation and pipeline compressor stations, this increased baseload capacity essentially reduces the installed costs per kilowatt by the percentage increase in the capacity of the unit, thus slightly reducing the cost impact of standards based on wet controls.

The economic impacts associated with standards based on either wet or dry controls would be small and are considered reasonable. Dry control costs are difficult to quantify. Many manufacturers, however, have indicated that the cost of dry controls would not exceed the cost of wet controls. Consequently, the analysis of the economic impact of standards of performance was based on the costs of wet controls and assumes that the costs of dry controls, and hence the economic impact of standards based on dry controls, would be comparable. Standards of performance, therefore, based on either wet or dry controls would increase the capital cost of a gas turbine for most applications by about 1 to 4 percent. For offshore industrial applications where desalinization equipment is required to provide water for wet controls, standards would result in a 7 percent increase in the capital cost of a gas turbine. The annualized costs for a stationary gas turbine in all applications would be increased by about 1 to 4 percent, with utility applications realizing less than a 2 percent increase.

Although it is unlikely that a stationary gas turbine would, of necessity, be installed in an arid area, an analysis was performed which assumed that water would have to be transported to the gas turbine site by truck over a distance of 50 miles. This unlikely situation would result in less than a 4 percent increase in the annualized cost of the gas turbine.

Standards of performance based on wet controls would increase the total capital investment requirements for all industrial and commercial users of large stationary gas turbines (greater than 10,000 hp) by about 36 million dollars by 1982. Total annualized costs would be increased by about 11 million dollars per year in 1982. Standards of performance based on wet controls would have an additional economic impact on users of small stationary gas turbines (less than 10,000 hp) beginning in 1987. Thus, for the period of 1982 through 1987, the capital investment requirements for all stationary gas turbine users would be about 67 million dollars. The total annualized costs would be about 30 million dollars by 1987. These impacts would translate into price increases for the end products or services provided by these industrial and commercial users of stationary gas turbines ranging from less than 0.01 percent in the petroleum refining industry to about 0.1 percent in the electric utility industry. Thus, the economic impact of standards of performance based on wet controls would be very small.

Standards of performance based on dry controls would have no economic impact by 1982. Following 1982, however, the economic impact of standards based on dry controls would be comparable to that of standards based on wet controls.

Based on this assessment of the impacts of standards of performance based on wet controls and dry controls, wet controls were selected as the " * * * best system of emission reduction (considering cost) * * * " for reduction of NO_x.

There are two possible control techniques for reducing SO_x emissions from stationary gas turbines: flue gas desulfurization (FGD) and the firing of low sulfur fuels. FGD, however, would cost about two to three times as much as the gas turbine. The economic impact of standards of performance for stationary gas turbines based on FGD, therefore, is not considered reasonable.

Low sulfur fuels, such as premium distillate oils or natural gas, are now being burned by nearly all stationary gas turbines. These premium fuels are being burned primarily because the increased maintenance costs associated with firing heavy fuel oils are greater than the savings that would be realized by buying these cheaper heavy or residual fuel oils. Over the next five to ten years, however, as oil prices continue to escalate, the price differential between premium distillate fuel oils and heavy fuel oils will probably increase and the economic incentive to burn the premium fuels will probably become marginal.

In this situation and in the absence of regulations requiring stationary gas turbines to fire specific fuels, the choice between firing either premium distillate fuel oils or heavy fuel oils will likely be decided on the basis of the relative convenience and availability of these fuels. Premium distillate fuel oils are more convenient to burn than heavy fuel oils because they have a lower viscosity and are easier to handle. Heavy fuel oils frequently require heating, for example, to reduce their viscosity to the point where they can be readily pumped from one location to another. Even if the price differential between premium distillate fuel oils and heavy fuel oils were to increase to the point where the firing of heavy fuel oils was marginally attractive, the greater inconvenience of scheduling and performing the additional maintenance would probably cause a gas turbine owner or operator to choose to fire the premium distillate fuel oil. On the basis of convenience, therefore, stationary gas turbines are likely to continue firing premium distillate fuel oils even if the economic incentive to do so becomes marginal.

The impact on ambient air quality of standards of performance based on the firing of low sulfur premium distillate fuel oils in gas turbines, therefore, would be negligible. The economic impact would also be negligible for the same reason and there would be no water, energy, solid waste or noise impact associated

with standards based on the firing of low sulfur premium distillate fuel oils.

Based on this assessment of the impacts of standards of performance based on the firing of low sulfur fuel oils, this control technique is selected as " * * * the best system of emission reduction (considering costs) * * * " for the reduction of SO_x emissions.

SELECTION OF FORMAT FOR THE STANDARDS

A number of different formats could be selected to limit NO_x emissions from stationary gas turbines. Mass standards limiting emissions in terms of power output (i.e., mass of emissions per unit of power output) or concentration standards limiting the concentration of emissions in the exhaust gases discharged into the atmosphere could be developed.

While mass standards may appear more meaningful in the sense that they relate directly to the quantity of emissions discharged into the atmosphere, enforcement of mass standards is more costly and the results more subject to error than enforcement of concentration standards.

Concentration standards, however, must be written to insure that the standards are not met merely by addition of dilution air. For combustion processes, this can be accomplished by correcting measured concentration to a reference concentration of O₂ (oxygen). The O₂ concentration in the exhaust gases is related to the excess (or dilution) air. Typical O₂ concentrations in gas turbine exhaust gases are about 15 percent. Thus, referencing standards to 15 percent oxygen effectively precludes circumvention by dilution. Consequently, concentration standards referenced to 15 percent oxygen were selected as the format for standards of performance for stationary gas turbines.

Selection of a concentration format, however, could penalize high efficiency gas turbines. Higher efficiencies are normally achieved by increasing combustor operating pressures and temperatures and NO_x formation generally increases exponentially with increased pressure and temperature. High efficiency turbines, therefore, generally discharge gases with higher NO_x concentrations than low efficiency turbines. A concentration standard based on low efficiency turbines could restrict the use of some high efficiency turbines. Conversely, a concentration standard based on high efficiency turbines could allow such high NO_x concentrations that low efficiency turbines would require no controls. Consequently, having selected a concentration format for standards of performance, an efficiency adjustment factor needed to be selected to permit higher NO_x emissions from high efficiency gas turbines.

NO_x emissions tend to increase exponentially with increased efficiency. It is not reasonable from an emission control viewpoint, however, 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 effi-

ciency. The objective of an efficiency adjustment factor should be to give an emission credit for the lower fuel consumption of high efficiency gas turbines. Since the relative fuel consumption of gas turbines varies linearly with efficiency, a linear efficiency adjustment factor is selected to permit increased NO_x emissions from high efficiency gas turbines. A linear efficiency adjustment factor also effectively limits NO_x emissions to a constant mass emission rate per unit of power output.

The efficiency adjustment factor must be referenced to a baseline efficiency. Since most existing simple cycle gas turbines fall in the range of 20 to 30 percent efficiency, 25 percent was selected as the baseline efficiency. The efficiency of stationary gas turbines is usually expressed in terms of heat rate which is the ratio of heat input, based on lower heating value (LHV) of the fuel, to the mechanical power output. The heat rate of a gas turbine operating at 25 percent efficiency is 14.4 kilojoules per watt-hr (10,180 Btu per hp-hr). Thus, the linear adjustment factor as presented in the regulation was selected to permit increased NO_x emissions from high efficiency stationary gas turbines.

The intent of the efficiency adjustment factor is to permit a linear increase in NO_x emissions with increased efficiencies above 25 percent. Consequently, the adjustment factor would not be used to adjust the emission limit downward for gas turbines with efficiencies of less than 25 percent.

The rationale for selection of the format for SO_x emissions is much the same as that discussed above for NO_x emissions. Thus, to be consistent with the format selected for standards limiting NO_x emissions, a concentration standard is chosen as the format for the SO_x standard. An emission limit in terms of percent fuel sulfur content has also been included in the SO_x standard to give the owner or operator the flexibility of either measuring the SO_x concentration of the exhaust gas or analyzing the fuel being fired in the turbine. Either format for the SO_x standard can be used since nearly all of the sulfur in the fuel is converted to SO_x.

The efficiency factor associated with the NO_x emission limit would not apply to the SO_x emission limit, however, because SO_x emissions do not vary with turbine efficiency.

SELECTION OF THE EMISSION LIMITS

The available data on emission from stationary gas turbines using wet controls come primarily from simple cycle gas turbine and combustor rig tests. No reliable data was available concerning NO_x emissions from regenerative cycle gas turbines using wet controls, although some dry control data was obtained. Careful consideration, therefore, was given to the question of whether regenerative cycle gas turbines could be controlled to the same emission levels as simple cycle gas turbines.

There is general agreement that wet controls will give essentially the same

percentage reduction in NO_x emissions from regenerative cycle gas turbines as from simple cycle gas turbines. Thus, the question becomes whether uncontrolled NO_x emissions from regenerative cycle gas turbines are higher than those from simple cycle gas turbines. On first comparison, NO_x emissions from regenerative cycle gas turbines appear higher than those from simple cycle gas turbines. Regenerative cycle gas turbines, however, frequently operate at higher thermal efficiencies than simple cycle gas turbines, and when NO_x emissions are plotted against gas turbine thermal efficiency, emissions from regenerative and simple cycle gas turbines do not appear significantly different. As a result, the application of wet controls to either regenerative or simple cycle gas turbines of comparable thermal efficiencies should reduce NO_x emissions to essentially the same level. Consequently, regenerative cycle gas turbines would be subject to the same emission limit as simple cycle gas turbines.

The data also indicate that gas turbines firing gaseous fuels typically have slightly lower controlled NO_x emission levels than gas turbines firing distillate fuels. Again, considering only the data representing major NO_x control efforts, controlled emissions from gas turbines firing gaseous fuels range from about 15 to 50 ppmv, while controlled emissions from gas turbines firing distillate fuels range from about 25 to 60 ppmv. This slight difference in controlled emission levels does not warrant the selection of a separate emission limit for each type of fuel. Only one emission limit, therefore, was selected which applies to gas turbines burning all types of fuel.

Based on this emission data and allowing for some uncertainty in the limited data base, 75 ppmv NO_x corrected to 15 percent oxygen was selected as the numerical emission limit for stationary gas turbines.

The gaseous and premium distillate fuels which have traditionally been burned in stationary gas turbines contain little or no "fuel-bound" or "organic" nitrogen. However, heavy residual fuel oils and crude oils can contain high levels of fuel-bound nitrogen. Total NO_x emissions from any combustion source, including stationary gas turbines, are a function of both thermal NO_x and organic NO_x formation. Thermal NO_x is formed in a well defined high temperature reaction between nitrogen and oxygen from the combustion air. Organic NO_x, however, is formed by the combination of fuel-bound nitrogen with oxygen during combustion. The reaction mechanism is not fully understood. Wet controls are effective for reducing thermal NO_x, but are not effective for reducing organic NO_x.

Three alternatives were considered to address the fuel-bound nitrogen contribution to total NO_x emissions from stationary gas turbines. The first alternative would have exempted heavy or residual fuel oils from standards of performance. This approach would have al-

lowed gas turbines firing heavy residual fuel oils to operate with no emission controls. In addition to the difficulties of distinguishing between premium and residual fuel oils in the standards, this approach would have encouraged owners or operators to burn heavy or residual fuel oils as a means of evading standards of performance.

The second alternative would have been to base standards of performance on the firing of low nitrogen fuels. This approach would have required emission controls on all new, modified, and reconstructed stationary gas turbines, but would have effectively precluded the firing of fuels other than those premium gaseous and distillate fuels which turbines are now using. Firing of heavy or residual fuel oils would have required major breakthroughs in controlling organic NO_x formation, or additional refining of these fuels to reduce their nitrogen content (as well as their sulfur content) to a level equivalent to that of premium distillate fuels.

The third alternative would include an adjustment to the NO_x emission limit as a function of the fuel-bound nitrogen level in the fuel fired. This approach would require NO_x controls on all new stationary gas turbines, but would not restrict new, modified or reconstructed gas turbines to firing premium gaseous and distillate fuels. Thus, stationary gas turbines would not be penalized for firing heavy fuel oils, nor would there be any added impetus toward the firing of heavy or residual fuel oils in order to evade standards of performance.

As discussed earlier, low sulfur fuels, such as premium distillate fuel oils or natural gas are now being fired by nearly all stationary gas turbines. These premium fuels are being fired primarily because the increased maintenance costs associated with firing heavy fuel oils are greater than the savings that would be realized by buying these less expensive heavy or residual fuel oils. Over the next five to ten years, however, as oil prices continue to escalate, the price differential between premium distillate fuel oils and heavy fuel oils will probably increase and economic incentive to fire the premium fuel oils will probably become marginal. It is also possible that there could be limited supplies of premium distillate fuel oils over the next five to ten years due to declining production of oil and natural gas in the United States, increased demands for these premium fuels by users other than gas turbines which cannot utilize heavy or residual fuel oils, and the uncertainty of additional crude oil supplies in the world energy markets. In fact, in anticipation of the possibility of limited supplies of premium distillate fuel oils, approximately 50 percent of the new gas turbines on order are being designed to allow the owner or operator the flexibility of firing either premium distillate fuel oils, or residual or heavy fuel oils. Consequently, in order to provide gas turbine owners and operators the flexibility to fire either premium or heavy and residual fuels, but to ensure that standards

performance add no impetus toward the firing of heavy fuel oils as a means of evading standards, alternative three selected for standards of performance limiting NO_x emissions from stationary gas turbines.

An allowance in the NO_x emission limit dependent on fuel-bound nitrogen level with no upper limit on emissions, however, could permit extremely high NO_x emissions when fuels with very high nitrogen contents are fired. Thus, it is essential that restraints be placed on such an emission allowance. Therefore, a fuel-bound nitrogen allowance was developed that allows approximately 50 percent availability of the heavy fuel oils. This corresponds to a fuel-bound nitrogen content of 0.25 percent. Firing a fuel with 0.25 percent nitrogen content increases controlled NO_x emissions by about 50 ppm.

The effect of ambient atmospheric conditions on NO_x emissions from stationary gas turbines is substantial. Large changes in relative humidity, for example, can cause NO_x emissions to vary by a factor of 2 or more. In order to insure that standards of performance are enforced uniformly, therefore, the effect of ambient atmospheric conditions was derived by extracting the common elements from several ambient condition correction factors proposed by gas turbine manufacturers. This correction factor, therefore, represents the general effect of ambient atmospheric conditions on NO_x emissions. Consequently, the ambient condition correction factor, as presented in the regulation, or an alternative correction factor as discussed below, will be used to adjust measured NO_x emissions during any performance test to determine compliance with the numerical emission limit.

As an alternative, gas turbine manufacturers, owners, or operators may elect to develop custom ambient condition correction factors for adjusting measured NO_x emissions from particular gas turbine models to ISO standard ambient conditions of pressure (101.3 kilopascals), humidity (60 percent relative humidity), and temperature (288 degrees Kelvin). Some gas turbine manufacturers have proposed ambient condition correction factors which include variables such as fuel-to-air ratios and combustor temperatures. These variables are difficult to measure and are operating parameters which may vary widely due to factors other than ambient conditions. For this reason, any custom ambient condition correction factor must be developed in terms of the following variables only: combustor inlet pressure, ambient air pressure, ambient air humidity, and ambient air temperature. All ambient condition correction factors must be substantiated with data and then approved for use by EPA before they can be used in determining compliance with the NO_x emission limit. Ambient condition correction factors will be applied to all performance tests, not only those in which the use of such factors would reduce measured emission levels.

Some delay is required before the NO_x standard of performance can be applied to small stationary gas turbines. A delay is necessary to provide time for manufacturers to incorporate NO_x controls on their small production stationary gas turbine models. It is estimated that about three years delay in the effective date of the standard for small stationary gas turbines would be required to allow manufacturers time to incorporate and test wet controls on these gas turbines. Some manufacturers have expressed optimism at being able to meet the NO_x standards using dry controls if given about five years delay. Since small gas turbines represent only about 10 to 15 percent of the total NO_x emissions from stationary gas turbines, the difference in environmental impact of a three-year versus five-year delay would be small. Additionally, a three-year delay would essentially force these manufacturers to incorporate wet controls, whereas a five-year delay would provide the flexibility to use wet controls or to develop and use dry controls. Consequently, five years was selected as the delay period for implementation of the NO_x emission limit on small stationary gas turbines.

In selecting the size cutoff to differentiate between large and small stationary gas turbines, consideration was given to the purpose for the cutoff and the effect on competitive markets. The purpose of the cutoff is to differentiate between large gas turbines where wet controls have been commercially demonstrated and small gas turbines where wet controls although effective, have not been generally applied on a commercial basis. Consideration of the market data reveals that there are two major competitive markets for stationary gas turbines which can be generally described as small gas turbines and large gas turbines. The size range of 5000 to 10,000 horsepower essentially separates these two markets. All gas turbines above this range are manufactured by companies which have developed wet control systems for their stationary gas turbines. The size cutoff, therefore, between small and large gas turbines was selected as the upper end of this range. Thus, large stationary gas turbines are defined as those with heat input at peak load of greater than 107.2 gigajoules per hour (approximately 10,000 horsepower for a 25 percent efficient gas turbine).

The best system of emission reduction, considering costs, selected for SO₂ emissions was the firing of low sulfur fuel oils. To be consistent with the objective of the fuel-bound nitrogen allowance NO_x emission limit and allow for approximately 50 percent availability of the residual and heavy fuel oils, the SO₂ emission limit is selected as 150 ppm referenced to 15 percent O₂, which corresponds to a fuel sulfur content of 0.8 percent by weight.

The five-year delay of the NO_x emission limit applied to small gas turbines (less than 10,000) to provide manufacturers time to incorporate wet controls onto their turbines would not apply to the SO₂ emission limit since the control tech-

nique of burning low sulfur fuels is now available to all turbines.

It should be noted that standards of performance for new sources established under Section 111 of the Clean Air Act reflect emission limits achievable with the best adequately demonstrated systems of emission reduction considering the cost of such systems. State implementation plans (SIP's) approved or promulgated under Section 110 of the Act, on the other hand, must provide for the attainment and maintenance of National Ambient Air Quality Standards (NAAQS) designed to protect public health and welfare. For that purpose SIP's must in some cases require greater emission reductions than those required by standards of performance for new sources. For example, EPA's Interpretative Ruling (41 FR 55524, December 21, 1976) on the construction of a new or modified source in an area that exceeds a NAAQS requires, among other things, that the new source must meet an emission limitation which reflects the "lowest achievable emission rate" for such type of source. At a minimum, the lowest rate achieved in practice would have to be specified unless the applicant can demonstrate that it cannot achieve such a rate. In no event could the rate exceed any applicable standard of performance for new sources.

This stringent requirement reflects EPA's judgment that a new source should be allowed to emit pollutants into an area violating a NAAQS only if its contribution to the violation is reduced to the greatest degree possible. While the cost of achievement may be an important factor in selecting a standard of performance for new sources applicable to all areas of the country, the cost factor must be accorded far less weight in determining an appropriate emission limitation for a source locating in an area violating statutorily-mandated health and welfare standards. Thus, while there may be technology available for new sources which have been determined not to be appropriate for standards of performance because of the consideration given to costs, this technology would be considered for purposes of determining the "lowest achievable emission rate" for such type of sources. Consequently, standards of performance for new sources should not be viewed as the ultimate in achievable control and should not limit the imposition of a more stringent standard, where appropriate.

States are free under Section 116 of the Act to establish even more stringent emission limits than those established under Section 111, or those necessary to attain or maintain the NAAQS under Section 110. Thus, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under Section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

SELECTION OF MONITORING REQUIREMENTS

To provide a convenient means for enforcement personnel to insure that an

emission control system installed to comply with standards of performance is properly operated and maintained, monitoring requirements are generally included in standards of performance. For stationary gas turbines, the most straightforward means of insuring proper operation and maintenance is to monitor emissions released to the atmosphere.

EPA has established NO_x monitoring performance specifications in Appendix B of 40 CFR Part 60 for large industrial sources with well developed velocity and temperature profiles. Stationary gas turbines, however, do not have well developed velocity and temperature profiles in all cases. Gas stratification of the turbine exhaust, for example, makes the location of the sample point critical. Also, since some gas turbines are started remotely from a central location, special systems and data reporting procedures would be necessary to start and maintain continuous monitors.

Currently there are no NO_x continuous monitors operating on gas turbines, and resolution of these sampling problems and development of performance specifications for continuous monitoring systems would entail a major development program. For these reasons, continuous monitoring of NO_x emission from gas turbines would not be required by the proposed standards.

An effective means of ensuring operation of the water injection system used to control NO_x emissions from gas turbines is to monitor the water-to-fuel ratio being fed to the turbine. Both water and fuel monitors are readily available and are demonstrated technology for use on gas turbines. Consequently, to ensure operation of water injection systems, the proposed standards for stationary gas turbines would require continuous monitoring of the water-to-fuel ratio where water injection is employed to comply with NO_x standard.

Also, an effective means of ensuring the firing of fuels with the proper nitrogen content to control NO_x emissions caused by fuel bound nitrogen is to monitor the nitrogen content of the fuel being fired. Consequently, any owner or operator that uses the fuel-bound nitrogen allowance to comply with NO_x emission limit will be required by the standard to monitor the nitrogen content of the fuel.

The continuous monitoring of SO₂ emissions would not be required by the proposed standards for the same reasons continuous monitoring of NO_x emissions would not be required. A means of ensuring the firing of low sulfur fuels to control SO₂ emissions, however, is to monitor the sulfur content of the fuel being burned. This is already a common practice among gas turbine users. Consequently, to ensure the use of low sulfur fuels by stationary gas turbines to comply with the SO₂ emission limit, the standard would require monitoring the sulfur content of the fuel.

SELECTION OF PERFORMANCE TEST METHODS

Reference Method 20, "Determination of Nitrogen Oxides, Sulfur Dioxide, and

Oxygen Emissions from Stationary Gas Turbines," was selected as the performance test method to determine compliance with the standards of performance limiting NO_x emissions for stationary gas turbines. This test method is based on the EPA gas turbine field tests and on background data for continuous monitoring system specifications (FEDERAL REGISTER, October 6, 1975). Reference Method 20 includes (1) measurement system design criteria, (2) measurement system performance specifications and performance test procedures, and (3) procedures for emission sampling. The performance specifications include the span drift, zero drift, linearity check, response time of the system, and interference checks. This method allows a choice of instruments and will provide reliable data if the performance specifications are met.

Both the Society of Automotive Engineers (SAE) and Mobile Source test methods are acceptable alternative methods. If the selected instrument models are capable of meeting the performance specifications of Reference Method 20.

NO_x emission measured by Reference Method 20 will be affected by ambient atmospheric conditions. Consequently, measured NO_x emissions would be adjusted during any performance test by the ambient condition correction factor discussed earlier, or by custom correction factors approved for use by the Administrator.

In order to apply the fuel-bound nitrogen allowance included as part of the NO_x emission limit, the nitrogen content of the fuel must be determined. The analytical methods and procedures employed to determine the nitrogen content of the fuel would be approved by the Administrator and would be accurate to within plus or minus five percent.

In lieu of determining the SO₂ concentration of the exhaust gas from a gas turbine by using Method 20, compliance with the standard may be demonstrated by determining the sulfur content of the fuels being used by the gas turbine. Sulfur content of the fuel will be determined using ASTM D2880-71 for liquid fuels and ASTM D1072-70 for gaseous fuels.

MISCELLANEOUS

As prescribed by Section 111 of the Act, this proposal of standards has been preceded by the Administrator's determination that emissions from stationary gas turbines contribute to air pollution which causes or contributes to the endangerment of public health or welfare, and by his publication of this determination in this issue of the FEDERAL REGISTER. In accordance with Section 117 of the Act, publication of these proposed standards was preceded by consultation with appropriate advisory committees, independent experts and Federal departments and agencies. The Administrator will welcome comments on all aspects of the proposed regulations, including the designation of stationary gas turbines as a significant contributor to air pollution which causes or contributes to the en-

dangerment of public health or welfare, economic and technological issues, and on the proposed test methods.

Comments are also specifically invited no the severity of the economic impact of the proposed standards on stationary gas turbines located offshore, since a number of interested parties have expressed objection to not exempting the offshore turbine from compliance with the standard. Any comments submitted to the Administrator on this issue, however, should contain specific information and data pertinent to an evaluation of the magnitude of this impact and its severity.

Economic impact analysis: The criteria for an action to be considered major, thereby requiring development of an Economic Impact Analysis (EIA) are: (1) an increase in the fifth-year annualized costs of 100 million dollars, (2) a major product price increase of 5 percent, or (3) an increase in national energy consumption of 25,000 barrels of fuel oil per day. The impacts resulting from the proposed standards would not exceed these criteria, except possibly for those stationary gas turbines sold for offshore oil and gas drilling platforms, where the proposed standards could increase the price of a gas turbine by about 7 percent. Most gas turbines used in the application, however, are likely to have a heat input at peak capacity of less than 107.2 gigajoules per hour (about 10,000 horsepower). Consequently, they would be considered small gas turbines and would be exempt from the standards for five years following proposal of the standards. In any event, however, stationary gas turbines sold for offshore applications constitute such a small percentage (estimated at less than 3 percent) of the overall market for stationary gas turbines that they are not considered a major product within the meaning of the 5 percent major product price increase criteria for an action to be considered major, thereby requiring preparation of an EIA. The Environmental Protection Agency has determined, therefore, that his proposed action does not constitute a major action requiring preparation of an Economic Impact Analysis under Executive Order 11821 and 11949 and OMB Circular A-107.

Dated: September 21, 1977.

DOUGLAS M. COSTLE,
Administrator.

It is proposed to amend Part 60 of Chapter I, Title 40 of the Code of Federal Regulations as follows:

1. By adding subpart GG as follows:

Subpart GG—Standards of Performance for Stationary Gas Turbines

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

AUTHORITY: Sections 111 and 301 (a) of the Clean Air Act, as amended, [42 U.S.C. 1857-7, 1857g(a)], and additional authority as noted below.

Subpart GG—Standards of Performance for Stationary Gas Turbines

§ 60.330 Applicability and designation of affected facility.

The provisions of this subpart are applicable to the following affected facilities: all stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour, based on the lower heating value of the fuel fired.

§ 60.331 Definitions.

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

(a) "Stationary gas turbine" means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self-propelled. It may, however, be mounted on a vehicle for portability.

(b) "Simple cycle gas turbine" means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) "Regenerative cycle gas turbine" means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) "Combined cycle gas turbine" means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) "Emergency gas turbine" means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) "Ice fog" means an atmospheric suspension of highly reflective ice crystals.

(g) "ISO standard day conditions" means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) "Efficiency" means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) "Peak load" means 100 percent of the manufacturer's design capacity of the gas turbine.

(j) "Base load" means the load level at which a gas turbine is normally operated.

(k) "Fire-fighting turbine" means any stationary gas turbine that is used primarily to pump water for extinguishing fires.

§ 60.332 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, except as provided in paragraphs (b), (c), and (d) of this section.

(1) From any gas turbine with a heat rate at peak load of more than or equal to 14.4 kilojoules per watt hour, based on the lower heating value of the fuel fired, any gases which contain nitrogen oxides in excess of:

$$STD=0.0075+F$$

where:

STD=allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).
F=NO_x emission allowance for fuel-bound nitrogen as defined in part (3) of this paragraph.

(2) From any gas turbine with a heat rate at peak load of less than or equal to 14.4 kilojoules per watt hour, based on the lower heating value of the fuel fired, any gases which contain nitrogen oxides in excess of:

$$STD=0.0075 \left(\frac{14.4}{Y} \right) + F$$

where:

STD=allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).
Y=manufacturer's rated heat rate at peak load (kilojoules per watt hour).
F=NO_x emission allowance for fuel-bound nitrogen as defined in part (3) of this paragraph.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F (NO _x percent by volume)
N < 0.015	0
0.015 < N ≤ 0.1	0.04(N)
0.1 < N ≤ 0.25	0.004 + 0.0087(N - 0.1)
N > 0.25	0.006

where:

N=the nitrogen content of the fuel (percent by weight).

(b) Stationary gas turbines with a heat input at peak load of 107.2 gigajoules per hour (100 million Btu/hour) or less, based on the lower heating value of the fuel fired, are exempt from paragraph (a) of this section for a period not to exceed five years from (date of proposal).

(c) Stationary gas turbines using water or steam injection for control of NO_x emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(d) Emergency standby gas turbines, military gas turbines for use in other than a garrison facility, and fire-fighting gas turbines are exempt from paragraph (a) of this section.

§ 60.333 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 stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) The sulfur content of the fuel fired by the gas turbine may be used to determine compliance with paragraph (a) of this section. Under such circumstances,

on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

§ 60.334 Monitoring of operations.

(a) The owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water injection to control NO_x emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within ±5.0 percent and shall be approved by the Administrator.

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall record daily the sulfur content, nitrogen content, and lower heating value of the fuel being fired in the gas turbine.

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

(1) Nitrogen oxides. Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with § 60.332 by the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under § 60.335(a).

(2) Sulfur dioxide. Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

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

§ 60.335 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.332 as follows:

(1) Reference Method 20 for the concentration of nitrogen oxides and oxygen.

(i) The nitrogen oxides emission level measured by Reference Method 20 shall be adjusted to ISO standard day conditions by the following ambient condition correction factor:

$$NO_x = (NO_{x,obs}) \left(\frac{P_{ref}}{P_{obs}} \right)^{0.5} e^{10(H_{obs}-9.0000)}$$

where:

NO_x = emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.
NO_{x,obs} = measured NO_x emissions at 15 percent oxygen, ppm v.
P_{ref} = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure.
P_{obs} = measured combustor inlet absolute pressure at test ambient pressure.
H_{obs} = specific humidity of ambient air at test.
e = transcendental constant (2.718).

The adjusted NO_x emission level shall be used to determine compliance with § 60.332.

(ii) Manufacturers, owners or operators may develop custom ambient condition correction factors in terms of combustor inlet pressure, ambient air pressure, ambient air humidity and ambient air temperature to adjust the nitrogen oxides emission level measured by the performance test as provided for in § 60.8 to ISO standard day conditions. These ambient condition correction factors shall be substantiated with data and must be approved for use by the Administrator before they can be used to determine compliance with paragraph (a) of this subpart. Notices of approval of custom ambient condition correction factors will be published in the FEDERAL REGISTER.

(iii) The water-to-fuel ratio necessary to comply with § 60.332 will be determined during the initial performance test by measuring NO_x emissions using Reference Method 20 and the water-to-fuel ratio necessary to comply with § 60.332 at 30, 50, 75, and 100 percent of peak load.

(2) ASTM D-2382 for the lower heating value of liquid fuels and ASTM D-1826 for the lower heating value of gaseous fuels. These methods shall also be used to comply with § 60.334(b).

(3) The analytical methods and procedures employed to determine the nitrogen content of the fuel being fired shall

be approved by the Administrator and shall be accurate to within plus or minus five percent.

(b) The method for determining compliance with § 60.333, except as provided in § 60.8(b), shall be as follows:

(1) Reference Method 20 for the concentration of sulfur dioxide and oxygen.

(2) ASTM D2880-71 for the sulfur content of liquid fuels and ASTM D1072-70 for the sulfur content of gaseous fuels. These methods shall also be used to comply with § 60.334(b).

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

APPENDIX A—REFERENCE METHODS

2. Part 60 is amended by adding Reference Method 20 to Appendix A as follows:

METHOD 20—DETERMINATION OF NITROGEN OXIDES, SULFUR DIOXIDE, AND OXYGEN EMISSIONS FROM STATIONARY GAS TURBINES

1. Principle and Applicability.

1.1 Principle. A gas sample is continuously extracted from the exhaust stream of a stationary gas turbine; a portion of the sample stream is conveyed to instrumental analyzers for determination of nitrogen oxides (NO_x) and oxygen (O₂) content. During each NO_x and O₂ determination, a separate measurement of sulfur dioxide (SO₂) emissions is made, using Method 6, or its equivalent. The O₂ determination is used to adjust the NO_x and SO₂ to a reference condition.

1.2 Applicability. This method is applicable for the determination of nitrogen oxide, sulfur dioxide, and oxygen emissions from stationary gas turbines. For the NO_x and O₂ determinations, this method includes: (1) Measurement system design criteria, (2) analyzer performance specifications and performance test procedures; and (3) procedures for emission testing.

2. Apparatus and Reagents

2.1 Measurement System. The equipment required to extract, transport, and analyze the gas sample constitutes the "measurement system." A schematic of the measurement system is shown in Figure 20-1. (Measurement system performance specifications are described in detail in Section 3.) The essential components of the measurement system are described below.

2.1.1 Probe. Stainless steel type 316 or equivalent, to transport gas from stack.

2.1.2 Particulate Filter. A filter is used to remove particulates ahead of the calibration valve assembly. In most cases, either in-stack or out-stack filter location is acceptable; however, out-stack filtration is required when the sample gas temperature is above 500°C (930°F). The filtration temperature shall be at least 120°C (250°F) to prevent moisture condensation. Glass fiber filters, of the type specified in EPA Method 6, or equivalent, are recommended.

2.1.3 Calibration Valve Assembly. A three-way valve assembly is used to direct the zero and span calibration gases to the analyzers. This assembly shall be located directly behind the probe and filter and shall be capable of blocking the sample gas flow and introducing the span and zero gases when the system is in the calibration mode.

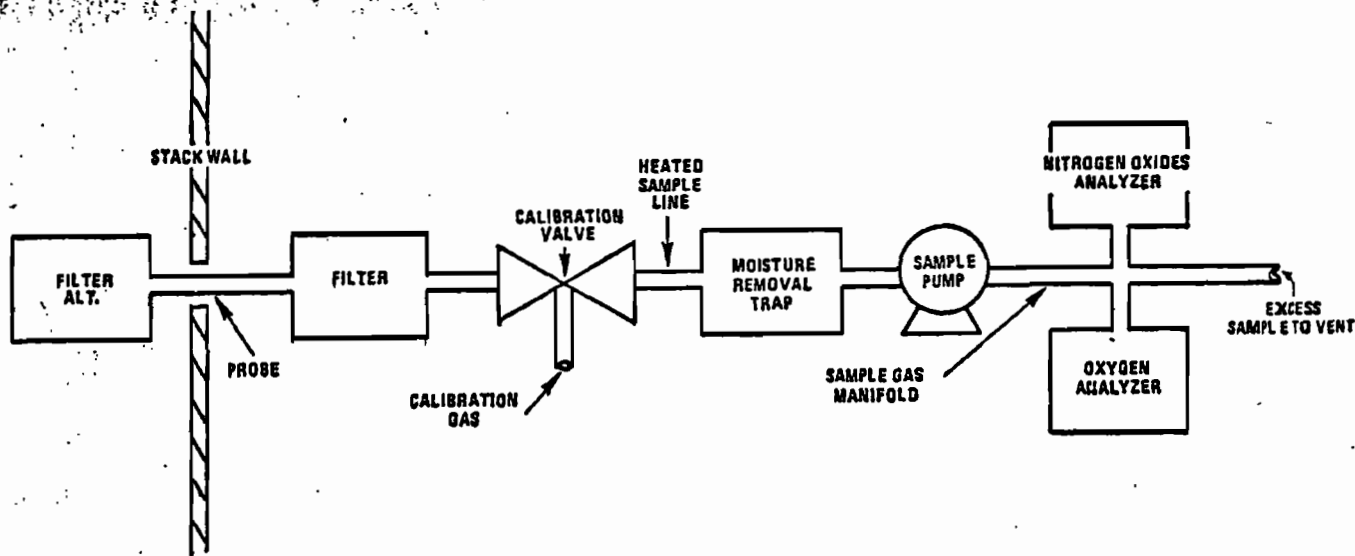


Figure 20.1 Measurement system design for stationary gas turbine tests.

2.1.4 Calibration Gases. Calibration gases are used to perform zero, span and calibration checks of the analyzers during each test run. The concentrations and specifications of these gases are described in detail in Sections 2.2 and 6.2.

2.1.5 Heated Sample Line. A FEP fluorocarbon or stainless steel (type 316 or equivalent) sample line is used to transport the gases to the sample conditioner and analyzers. The sample gas shall be maintained at least 5°C (10°F) above the stack gas dew point to prevent moisture condensation.

2.1.6 Moisture Trap. A moisture trap, designed to reduce the dew point of the sample gas to 3°C (37°F) or less, is used. For instruments not affected by water vapor, this device is not required; however, the moisture

content shall be determined using methods subject to the approval of the Administrator and the NO_x and O₂ concentrations shall be corrected to a dry gas basis.

2.1.7 Pump. A nonreactive leak-free sample pump is used to pull the sample gas through the system at a flow rate sufficient to minimize transport delay. The pump shall be made from or coated with nonreactive material (FEP fluorocarbon or type 316 stainless steel).

2.1.8 Sample Gas Manifold. A sample gas manifold is recommended for diverting portions of the sample gas stream to the analyzers. The manifold may be constructed of glass, FEP fluorocarbon, or stainless steel (type 316 or equivalent). Instead of using

the manifold, separate sample lines may be connected to each analyzer.

2.1.9 Oxygen Analyzer. An oxygen analyzer is used to determine the oxygen concentration (percent O₂) of the sample gas stream.

2.1.10 Nitrogen Oxides Analyzer. A NO_x analyzer is used to determine the ppm concentration of nitrogen oxides in the sample gas stream.

2.1.11 Sulfur Dioxide Analysis. Method 6 apparatus, or equivalent, is required for sulfur dioxide determination.

2.2 Calibration Gas Specifications.

2.2.1 Zero Gas. Prepurified nitrogen is used.

2.2.2 Nitrogen Oxide Calibration Gases. Mixtures of known concentrations of NO_x

nitrogen are required. Nominal NO concentrations of 25, 50, and 90 percent of the instrument full scale range are needed. The 90 percent gas mixture is used to set and check the instrument span and is referred to as span gas. The 25 and 50 percent gas mixtures shall be used to validate the analyzer calibration, prior to each test.

2.2.3 Oxygen Calibration Gases. Ambient air at 20.9 percent oxygen shall be used as the span gas (high range concentration gas). A midscale calibration gas (approximately 13 percent O₂ in nitrogen) shall be used to validate the analyzer calibration prior to each test.

2.2.4 Concentration Validation. Within one month prior test use, calibration gases shall be analyzed, by the appropriate test method specified in Section 6.2, to determine their true concentration levels. Gas concentrations that are traceable to the National Bureau of Standards and which can be demonstrated to be stable are exempted from the analysis requirements.

3. Measurement System Performance Specifications and Performance Test Procedures.

3.1 Analyzer. "Span" is defined as the concentration range (specified by manufacturer) over which an analyzer will give valid readings. The spans for the analyzers used in this method shall be as follows:

3.1.1 Oxygen Analyzer: 0 to 25% O₂.

3.1.2 NO_x Analyzer: 0 to 120 ppm.

3.2 Analyzer Interferences and Interference Response. The "interference response" of an analyzer is defined as the output response to a component in the sample gas stream, other than the gas component being analyzed; the analyzers used in this method shall not have a total interference response of more than ±2 percent of span.

Particulate matter and water vapor are the primary interfering species for most instrumental analyzers, but these may be removed physically by using filters and condensers. Other possible specific interferences found in turbine exhaust streams include carbon monoxide, carbon dioxide, nitrogen oxides, sulfur dioxide and hydrocarbons. Each analyzing instrument may respond to one or more of these interferences in ways that alter the desired measurement.

The interference response of an analyzer is determined by measuring the total analyzer response to the gaseous components (or mixtures) listed in Table 20.1; these gases may either be introduced into the analyzer separately, or as a single gas mixture. The total interference output response of the analyzer to these components, if any, shall be determined (in concentration units). The values obtained in an interference response test shall be recorded on a form similar to Figure 20.2.

If the sum of the interference responses of the test gases is greater than 2 percent of the instrument span, the analyzer shall not be used in the measurement system of this method.

An interference response test of each analyzer shall be conducted prior to its initial use in the field. Thereafter, if changes are made in the instrumentation which could alter the interference response, e.g., changes in the type of gas detector, the instruments shall be retested.

In lieu of conducting the interference response test, instrument vendor data, which demonstrate that for the test gases of Table 20.1 the interference performance specification is not exceeded, are acceptable. If these data are not available, the tests shall be made.

3.3 Analyzer Response Time. When a change in pollutant concentration occurs at the inlet of the measurement system (i.e., at probe), the change is not immediately registered by the analyzer; "response time" is defined as the amount of time that it takes for the analyzer to register a concentration value within 5 percent of the new inlet concentration. The maximum response time for the analyzers used in this method is three minutes.

To determine response time, first introduce zero gas into the system until all readings are stable; then, introduce span gas into the system. The amount of time that it takes for the analyzer to register 95 percent of the final span gas concentration is the upscale response time. Next, reintroduce zero gas into the system; the length of time that it takes for the analyzer output to come within 5 percent of the final reading is the downscale response time. The upscale and downscale response times shall each be measured three times. The readings shall be averaged, and the average upscale or downscale response time, whichever is greater, shall be reported as the "response time" for the analyzer. Response time data are recorded on a form similar to Figure 20.3. A response time test shall be conducted prior to the initial field use of the measurement system, and shall be repeated if changes are made in the measurement system.

3.4 Zero Drift. "Zero drift" is the change in analyzer output during a turbine performance test, when the input to the measurement system is a pure grade of nitrogen (zero gas). The maximum allowable zero drift for the analyzers used in this method is ±2 percent of the specified instrument span. The zero drift calculation is made for each gas for each turbine test run; this is done by taking the difference of the zero gas concentration values measured at the start and finish of the test (see Section 6.1). The zero drift is recorded as a percentage of the instrument span) on a form similar to Figure 20.4.

3.5 Span Drift. "Span drift" is the change in the analyzer output during a turbine performance test, when the input to the measurement system is span gas. The maximum allowable span drift for the analyzers used in this method is ±3 percent of the specified instrument span. The span drift calculation is to be made for each gas for each turbine test run; this is done by taking the difference between the span gas concentration values measured at the beginning and end of the test. Span drift is recorded (as a percentage of instrument span) on a form similar to Figure 20.4. Span drift must be corrected for any zero drift that occurred during the test period (see Figure 20.4).

4. Procedure for Field Sampling.

4.1 Selection of a Sampling Site and the Minimum Number of Traverse Points.

TABLE 20.1 INTERFERENCE TEST GAS CONCENTRATIONS

CO	500 ppm
SO ₂	200 ppm
NO/NO ₂	200 ppm
CO ₂	10%
O ₂	20.9% (Air)

FIGURE 20.2 INTERFERENCE RESPONSE

Date of Test: _____

Analyzer Type: _____ S/N _____

Test Gas Type	Conc.	Analyzer Output Response	% of Span

$$\% \text{ of Span} = \frac{\text{Analyzer Output Response}}{\text{Instrument Span}} \times 100$$

PROPOSED RULES

RESPONSE TIME

Date of Test _____	
Analyzer Type _____	S/N _____
Span Gas Concentration _____ ppm	
Analyzer Span Setting _____ ppm	
Upscale	1 _____ seconds
	2 _____ seconds
	3 _____ seconds
Average upscale response _____ seconds	
Downscale	1 _____ seconds
	2 _____ seconds
	3 _____ seconds
Average downscale response _____ seconds	
System response time = slower average time = _____ seconds.	

Figure 20.3

TURBINE SAMPLING SYSTEM

Zero and Span Drift Data				
Turbine Type _____		S/N _____		
Date: _____				
Test No.: _____				
Analyzer: Type _____		S/N _____		
	Initial Calibration ppm or %	Final Calibration ppm or %	Difference Initial-Final ppm or %	% of Span
Zero Gas				
High Calibration Gas (Span Gas)			*	
$\% \text{ of Span} = \frac{\text{Absolute Value of Difference}}{\text{Instrument Span}} \times 100$				
*Corrected for zero drift, i.e., if zero drift over test period is +2 ppm then 2 ppm shall be subtracted from the difference between the initial and final readings.				

Figure 20.4

4.1.1 Select a sampling site as close as practical to the exhaust of the turbine. Turbine geometry, stack configuration, internal baffling, and point of introduction of dilution air will vary for different turbine designs. Thus, each of these factors must be given special consideration in order to obtain a representative sample. Whenever possible, the sampling site shall be located upstream of the point of introduction of dilution air into the duct. Sample ports may be located before or after the upturn elbow, in order to accommodate the configuration of the turning vanes and baffles and to permit a complete, unobstructed traverse of the stack. The sample ports shall not be located within 5 feet or 2 diameters (whichever is less) of the gas discharge to atmosphere. For supplementary-fired, combined-cycle plants, the sampling site shall be located between the gas turbine and the boiler.

4.1.2 The minimum diameter of the sample ports shall be 3-inch nominal pipe size (NPS).

4.1.3 The minimum number of points for the preliminary O₂ sampling (Section 8.3.2) shall be as follows: (1) eight, for stacks having cross-sectional areas less than 1.5 m² (16.1 ft²); (2) one sample point for each 0.2 m² (2.2 ft²) of area, for stacks of 1.5 m² to 10.0 m² (16.1-107.6 ft²) in cross-sectional area; and (3) one sample point for each 0.4 m² (4.4 ft²) of area, for stacks greater than 10.0 m² (107.6 ft²) in cross-sectional area. Note that for circular ducts, the number of sample points must be a multiple of 4, and for rectangular ducts, the number of points must be one of those listed in Table 20.2; therefore, round off the number of points (upward), when appropriate.

TABLE 20.2.—Cross-sectional layout for rectangular stacks

No. of traverse points:	Matrix layout
9	3×3
12	4×3
16	4×4
20	5×4
25	5×5
30	6×5
36	6×6
42	7×6
49	7×7

4.2 Cross-sectional Layout and Location of Traverse Points. After the number of traverse points for the preliminary O₂ sampling has been determined, use Method 1 to locate the traverse points.

4.3 Measurement System Operation.

4.3.1 Preliminaries.

4.3.1.1 Prior to the turbine test, the measurement system shall have been demonstrated to have met the performance specifications for interference response and response time described in Sections 3.2 and 3.3.

4.3.1.2 Turn on the sample pump and instruments; allow the normal warmup time required for stable instrument operation.

4.3.1.3 After the instruments have stabilized, the measurement system shall be calibrated using the procedures detailed in Section 6.1. Transfer the zero and span gas calibration data from Figure 20.5 to a form similar to Figure 20.4.

4.3.1.4 At the beginning of each NO_x test run and, as applicable, during the run, record turbine data as indicated in Figure 20.6. Also, record the location and number of the traverse points on a diagram.

4.3.2 Preliminary Oxygen Sampling.

4.3.2.1 At the start of a 3-run sample sequence, position the probe at the first traverse point and begin sampling. The minimum sampling time at each point shall be 1

minute plus the average system response time. Determine the average steady-state concentration of O₂ at each point and record the data on Figure 20.7.

Figure 20.5

CALIBRATION DATA

Date	_____
Analyzer Type	_____ S/N _____
High Range Gas Conc.	_____ % Full Scale _____
Mid Range Gas Conc.	_____ % Full Scale _____
Low Range Gas Conc.	_____ % Full Scale _____
Zero Gas	_____ % Full Scale _____

Figure 20.6

STATIONARY GAS TURBINE

TURBINE OPERATION RECORD

Test Operator	_____	Date	_____
Turbine ID	Type _____ S/N _____	Ultimate Fuel Analysis	C _____ H _____ O _____ N _____ S _____ Ash _____ H ₂ O _____
Location	Plant _____ City _____	Trace Metals	_____
Ambient Temperature	_____	Test Time Start	_____
Ambient Humidity	_____	Test Time Finish	_____
		Fuel Flow Rate	_____ *
		Water or Steam Flow Rate	_____ * Operating Load _____
		Ambient Pressure	_____

*Describe measurement method, i.e., continuous flow meter, start finish volumes, etc.

**i.e., Additional elements added for smoke suppression.

Figure 20.8
STATIONARY GAS TURBINE
GAS SAMPLE POINT RECORD

Turbine ID Mfg. _____
 Model & S/N _____
 Plant _____
 Location City _____
 State _____
 Ambient Temp. _____
 Ambient Press _____
 Ambient Humidity _____
 Date _____
 Test Time Start _____
 Test Time Finish _____

Test Operator Name _____
 O₂ Instrument Type _____ S/N _____
 NO_x Instrument Type _____ S/N _____

Sample Point	Time (Min)	O ₂ [*] (%)	NO _x [*] (ppm)
1	0		

*Average steady state value from recorder or instrument readout.

5. Emission Calculations.

5.1 Correction to 15 Percent Oxygen. Using Equation 20-1, calculate the NO_x and SO₂ concentrations (adjusted to 15 percent O₂). The correction to 15 percent oxygen is sensitive to the accuracy of the oxygen measurement. At the level of analyzer drift specified in the method (± 2 percent of full scale), the change in the oxygen concentration correction can exceed 10 percent when the oxygen content of the exhaust is above 16 percent O₂. Therefore O₂ analyzer stability and careful calibration are necessary.

Actual pollutant concentration (NO_x or SO₂)

$$\times \frac{5.9\%}{20.9\% - O_2\% \text{ actual}} =$$

Pollutant concentration adjusted to 15% O₂

where: 5.9% is 20.9% - 15% (the defined concentration basis).

O₂ actual is the sample point oxygen concentration for NO_x calculation, and the average O₂ concentration for SO₂ calculation.

5.2 Calculate the average adjusted NO_x concentration by summing the point values and dividing by the number of sample points.

6. Calibration.

6.1 Measurement System. Prior to each turbine test, the measurement system shall be calibrated according to the procedures described below. The manufacturer's operation and calibration instructions are also to be followed as required for each specific analyzer.

6.1.1 Turn on all measurement system components and allow them to warm up until stable conditions are achieved. Next, introduce zero gas and each of the calibration gases described in Section 6.2, one at a

PROPOSED RULES

time, into the inlet of the probe. The responses of the analyzer to these gases shall be used to establish a calibration curve or to verify the manufacturer's calibration curve. The data obtained in these procedures shall be recorded on a form similar to Figure 20.4. If, for the mid-scale gases, the accuracy of the manufacturer's calibration curve or the expected response curve cannot be shown to be ± 2 percent of full scale (or better), the calibration shall be considered invalid and corrective measures on the instrument shall be taken. The calibration procedure shall be repeated, using only zero gas and span gas, at the conclusion of test; this

allows calculation of zero and span drift (Sections 3.2 and 3.3).

6.2 Calibration Gas Mixtures.

6.2.1 Within one month prior to the turbine test, the NO_x calibration gas mixtures shall be analyzed, using the phenoldisulfonic acid procedure (Method 7) for nitrogen oxides. A minimum of three analyses shall be done, and the average concentration of each gas shall be reported as the true calibration gas value (see Figure 20.9). Alternate procedures may be employed, subject to the approval of the Administrator, to determine the calibration gas concentration.

Figure 20.9

ANALYSIS OF CALIBRATION GAS MIXTURES

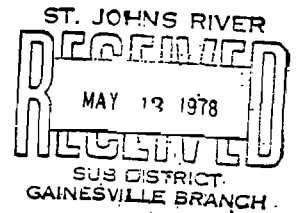
CYLINDER GAS COMPOSITION	Reference Method Used _____
Data _____	
<u>Low Range Calibration Gas Mixture</u>	
Sample 1 _____	ppm
Sample 2 _____	ppm
Sample 3 _____	ppm
Average _____	ppm
<u>Mid Range Calibration Gas Mixture</u>	
Sample 1 _____	ppm
Sample 2 _____	ppm
Sample 3 _____	ppm
Average _____	ppm
<u>High Range (span) Calibration Gas Mixture</u>	
Sample 1 _____	ppm
Sample 2 _____	ppm
Sample 3 _____	ppm
Average _____	ppm

NOTE.—The NO_x calibration gas mixtures shall contain nitric oxide (NO) in nitrogen. Instruments which require conversion of one nitrogen oxide component to another for total NO_x measurement shall be checked to ensure that this conversion is complete and reproducible, as specified by the manufacturer.

6.2.2 Ambient air may be used as the oxygen span gas. The mid-scale calibration gas concentration shall be certified (by vendor) as being within ± 2 percent of the indicated concentration.

[FR Doc.77-28721 Filed 9-30-77; 8:45 am]

ATTACHMENT A
COMPLETE BACT APPLICATION



STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION
APPLICATION FOR DETERMINATION OF BEST
AVAILABLE CONTROL TECHNOLOGY FOR AIR POLLUTION SOURCES

SOURCE STATUS: (x) New () Modification
Company Name: FLORIDA POWER CORPORATION County: Suwannee
Source Identification: Suwannee River Plant Peaking Unit Addition
Source Location: Street: Suwannee River Plant Site City: _____
UTM: East: 503,673 North: 2,415,157 (coordinates of existing center stack)
Appl. Name and Title: J. T. Rodgers, Assistant Vice President
Appl. Address: P. O. Box 14042, St. Petersburg, FL 33733
Appl. Phone: 813/866-4765

DEPARTMENT USE ONLY

Date Appl. Received: May 12, 1978
Notice of Receipt:
Newspaper: Florida Times Union Date: June 30, 1978
Florida Administrative Weekly Date: June 23, 1978
BACT Determination: _____
Declared by Secretary: _____ Date: _____
BACT: _____

NOTICE OF DETERMINATION

Newspaper: _____ Date: _____
Florida Administrative Weekly Date: _____

NOTE: All data is for one (1) gas turbine unit operating at a peak load of 63,000 MW at an ambient temperature of 59°F.

I. DETAILED DESCRIPTION OF SOURCE

A. Describe The Manufacturing Process at the Facility and the Unit Operation to be Controlled. Discuss the Source of Emissions, Existing Control Devices, the Expected Improvement in Performance, With Ambient Air Quality Standards or Applicable PSD Increments. Attach Additional Sheet If Necessary.

See attached Exhibit A

B. For This Source Indicate Any Previous DER Permits, Order and Notices; Including Issuance Dates and Expiration Dates.
None

C. Raw Materials, Fuels, and Chemicals Used:

DESCRIPTION	HOURLY USE	CONTAMINANT		RELATION TO FLOW DIAGRAM
		TYPE	%WT.	
Distillate Fuel Oil	37,910#/hr	Ash	0.1% Max	(2)
		Sulfur	0.5% Max	
Air	2,196,000#/hr			(1)

D. Process Rate

1. Total Process Input Rate: 2,235,000#/hr (Air and Fuel)
2. Produce Output Rate: 2,235,000#/hr (Exhaust Gas)
3. Operation Time: 1,500 Hrs/yr

a. ~~XXXXXX~~ b. ~~XXXXXX~~ c. ~~XXXXXX~~

d. Seasons: Operate daytime and early evenings to supply power during periods of high system electrical load for a range of 4 hours per run and during emergency conditions.

II. BEST AVAILABLE CONTROL TECHNOLOGY DATA

A. Emission Limitations For Any Pollutants Emitted From The Source Pursuant To 17-2, F.A.C.?

Yes (<input checked="" type="checkbox"/>)	No (<input type="checkbox"/>)	FOR CLASS II AREA MAXIMUM ALLOWABLE INCREASE IN CONCENTRATIONS RATE OR CONCENTRATION	
CONTAMINANT		RATE OR CONCENTRATION	
Particulate		Annual geometric mean: 19 ug/m ³	24 hr max 37 ug/m ³
SO _x as SO ₂		Annual arithmetic mean: 20 ug/m ³	3 hr max: 512 ug/m ³
NO _x as NO ₂		-----	-----
HC as (H ₄)		-----	-----
CO		-----	-----
Visible emissions & opacity		Less than 20%	

B. Are Standards Of Performance For New Stationary Sources Pursuant To 40 C.F.R. Part 60 Applicable To The Source?

Yes (<input type="checkbox"/>)	No (<input checked="" type="checkbox"/>)	However standards are proposed for SO _x and NO _x see below and footnote.	
CONTAMINANT		RATE OR CONCENTRATION	
Particulate		*Not Applicable	
SO _x as SO ₂		*150 ppm by volume	
NO _x as NO ₂		** 75 ppm by volume STD (Allowable emission)	
HC as (H ₄)		*Not Applicable	
CO		*Not Applicable	

C. Has EPA Declared The Best Available Control Technology For This Class Of Sources? (If Yes Attach Copy)

Yes (<input type="checkbox"/>)	No (<input checked="" type="checkbox"/>)	
CONTAMINANT		RATE OR CONCENTRATION
_____		_____
_____		_____
_____		_____
_____		_____

*Reference is made to page 53783, Selection of Pollutants, Federal Register, Vol. 42, No. 191, Monday, October 3, 1977.

**The actual NO_x Emission Rate is adjusted according to the requirements on Page 53789 of the above referenced Federal Register.

D. What Emission Levels Do You Propose As Best Available Control Technology? Also see D continued at bottom of page.

CONTAMINANT	(ACTUAL ESTIMATED EMISSIONS)	
	RATE OR CONCENTRATION Lbs/Hr	T/Yr
Particulate	38	28.5
SO _x as SO ₂	379	284
NO _x as NO ₂	250	187.5
HC as (H ₄)	9	6.75
CO	86	64.5

E. Describe The Existing Control and Treatment Technology (If Any) N/A

1. Control Device:
2. Operating Principles:
3. Efficiency*:
4. Capital Costs:
5. Useful Life:
6. Operating Costs:
7. Energy:
8. Maintenance Cost:
9. Emissions:

CONTAMINANT	RATE OR CONCENTRATION	
	Before Device	After Device
_____	_____	_____
_____	_____	_____
_____	_____	_____
_____	_____	_____

10. Stack Parameters

- | | | | |
|---------------|------|-----------------|-----|
| a. Height: | Ft. | b. Diameter: | Ft. |
| c. Flow Rate: | ACFM | d. Temperature: | °F |
| e. Velocity: | FPS | | |

D. (Continued)

CONTAMINATE	RATE OR CONCENTRATION
SO _x as SO ₂	95 ppm by volume
NO _x as NO ₂	**75 ppm by volume STD (Allowable Emission)
Opacity	Less than 20%

F. Describe The Control and Treatment Technology Available
(As Many Types As Applicable Use Additional Pages If Necessary)

1. NO₂ Control and Treatment Technology (Wet Method) See Exhibit B
 - a. Control Device:
 - b. Operating Principles:
 - c. Efficiency:Footnote) (See
 - d. Capital Cost: \$945,000.
 - e. Life: 20 years
 - f. Operating Cost:\$759,000 per year
 - g. *Energy: 375,000 KWHR
 - h. Maintenance Cost: Significant information is presently unavailable to determine maintenance Cost
 - i. Availability of Construction Material and Process Chemicals: Equipment is available and demineralized water will be used for the control process
 - j. Applicability to Manufacturing Processes: The control strategy is well adapted to the process and is currently available
 - k. Ability to Construct with Control Device, Install In Available Space, and Operate within Proposed Levels: The plant site has adequate space to install the necessary water treatment and storage facility for the NO_x control.
2. NO₂ Control and Treatment Technology (Dry Method) See Exhibit B
 - a. Control Device: Insufficient information is available from manufacturers on dry NO_x control to complete
 - b. Operating Principles: this section, since the equipment is not commercially available at the present time. The Company cannot indicate that dry NO_x control is a practical control method at
 - c. Efficiency: the present time.
 - d. Capital Cost: However, the Company is leaving the option
 - e. Life: f. Operating Cost: open in that this control methodology may be demonstrated soon
 - g. Energy: h. Maintenance Cost: by manufacturer's test programs.
 - i. Availability of Construction Materials and Process Chemicals:
 - j. Applicability to Manufacturing Processes:
 - k. Ability to Construct with Control Device, Install In Available Space, and Operate within Proposed Levels:

* Energy to be Reported in Units of Electrical Power - KWH Design Rate.

- F. 1. (c) Efficiency: Description of NO_x control will be in accordance with specifications of a particular manufacturer. Use of steam is not contemplated since boilers will not be installed on site. Water injection will be used with expected efficiency - adequate to reduce the NO_x emission level to 75 ppm by volume (Standard) (Allowable Emission)**

3. SO₂ Control and Treatment Technology

- a. Control Device: Distillate fuel will not exceed .5% sulfur by weight
- b. Operating Principles:
 - (See Footnote Below)
- c. Efficiency: The capital cost is lower when using distillate fuel when compared to a higher sulfur less expensive fuel.
- d. Capital Cost: sulfur less expensive fuel.
- e. Life:
- f. Operating Cost:
- g. Energy:
- h. Maintenance Cost:
- i. Availability of Construction Materials and Process Chemicals:
- j. Applicability to Manufacturing Processes:

The control strategy is well suited to the process.
- k. Ability to Construct with Control Device, Install In Available Space, and Operate within Proposed Levels: It is anticipated that no difficulties will be realized in acquiring the low sulfur fuel to meet the aforementioned control technology for SO₂. Appropriate contract(s) would be secured subsequent to acquiring all necessary governmental licensing for the project.

4.

- a. Control Device:
- b. Operating Principles:
- c. Efficiency:
- d. Capital Cost:
- e. Life:
- f. Operating Cost:
- g. Energy:
- h. Maintenance Cost:
- i. Availability of Construction Materials and Process Chemicals:
- j. Applicability to Manufacturing Processes:
- k. Ability to Construct with Control Device, Install in Available Space, and Operate within Proposed Levels:

- 3 (c). Efficiency: For peaking unit installations, low sulfur distillate fuel is normally used to provide maximum reliability. There is no feasible control device for removing SO₂ from a combustion turbine exhaust gas when high sulfur fuel is used. (High sulfur fuel is defined as that with a sulfur content over 0.8% which would exceed the EPA proposed emission limits).

G. Describe the Control Technology Selected: SO₂ Control will be Distillate Fuel Oil, NO_x Control: Wet or Dry Method. See Para. 10, REASONS FOR SELECTION

1. Control Device: AND DESCRIPTION OF SYSTEMS and attached Exhibit B. Also refer to F1, 2, & 3 on the preceding two pages.

2. Efficiency:

3. Capital Cost:

4. Life:

5. Operating Cost:

6. Energy:

7. Maintenance Cost:

8. Manufacturer: General Electric Co., Westinghouse Corp., Brown Boveri, United Technologies.

9. Other locations Where Employed on Similar Processes: Presently is not employed at any FPC facility

a.

(1) Company:

(2) Mailing Address:

(3) City:

(4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:

CONTAMINANT

RATE OR CONCENTRATION

CONTAMINANT	RATE OR CONCENTRATION
_____	_____
_____	_____
_____	_____
_____	_____

(8) Process Rate:

b.

(1) Company:

(2) Mailing Address:

(3) City:

(4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:

CONTAMINANT

RATE OR CONCENTRATION

(8) Process Rate:

c.

(1) Company:

(2) Mailing Address:

(3) City:

(4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:

CONTAMINANT

RATE OR CONCENTRATION

(8) Process Rate:

d.

(1) Company:

(2) Mailing Address:

(3) City:

(4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:

CONTAMINANT

RATE OR CONCENTRATION

d. (7) Emissions: (continued)

CONTAMINANT	RATE OR CONCENTRATION

(8) Process Rate:

c.

- (1) Company:
- (2) Mailing Address:
- (3) City: (4) State:
- (5) Environmental Manager:
- (6) Telephone No.:
- (7) Emissions:

CONTAMINANT	RATE OR CONCENTRATION

(8) Process Rate:

- 10. Reason For Selection and Description of Systems: NO_x Control - recommendation from manufacturer to be requested in Specs. Methodology available Wet & Dry Method, See Exhibit B. Specifications will require compliance with Federal and State regulations on NO_x Control.
- SO₂ Control - Fuel - Reason: Only existing feasible control technology available for SO₂.
- 11. Emissions:

CONTAMINANT	ACTUAL ESTIMATED MAXIMUM DISCHARGE	
	RATE OR CONCENTRATION Lbs/Hr	T/Hr
Particulate	38	28.5
SO _x as SO ₂	379	284
NO _x as NO ₂	250	187.5
HC as (H ₄)	9	6.75
CO	86	64.5

12. Stack Parameters:**

- a. HEIGHT: 22 Ft. Minimum
- b. Cross sectional area 130 sq. ft. (Rectangular)
- c. Gas Flow Rate: 1,255,500 ACFM
- d. Gas Exit Temperature: 726°F to 800°F
- e. Velocity: 153 FPS

** Depending on the selection of a manufacturer, there will be one or two stacks per unit.

13. Fuels:

TYPE	HOURLY USE*		HOURLY HEAT INPUT MILLION BTU/HR.	
	AVG.	MAX.	AVG.	MAX.
Distillate Fuel Oil	Varies	37,910	Varies	739 X 10 ⁶ BTU/HR.

NOTE; Fuel consumption will vary with load and ambient temperature. The consumption listed is for one (1) gas turbine unit operating at peak load at 59°F ambient temperature.

TYPE	DENSITY	%S Maximum by % Weight	%N	%ASH Maximum
Distillate Fuel Oil	6.8 Lb/Gal	0.5%		0.1%

*Gaseous Cu. Ft./Hr. Liquid & Solid: Lbs./Hr.

14. Wates Generated, Disposal Method, Cost of Disposal; Waste water due to water demineralization plant may be disposed of in existing percolation pond. Appropriate licensing will be acquired from the DER if wet method of NO_x Control is choosen.

H. Discuss the Social Impact of the Selected Technology Versus Other Applicable Technologies. (i.e. Jobs, Payroll, Production, Taxes, Energy, Etc.)
Include Assessment of the Environmental Impact of the Sources

Social Impacts: See Exhibit C

Environmental Impacts: See Exhibit D

III. ADDITIONAL ATTACHED INFORMATION.

- A. Show Derivation of Total Process Input Rate and Product Weight.
- B. Show Derivation of Efficiency Estimation. See B below.
- C. An 8½"x 11" Flow Diagram Which Will, Without Revealing Trade Secrets, Identify the Individual Operations and/or Processes. Indicate Where Raw Materials Enter, Where Solid and Liquid Waste Exist, Where Gaseous Emissions and/or Airborne Particles Are Evolved and Where Finished Products Are Obtained.
See Dwg. No. SRP-L3-A-0
- D. An 8½"x 11" Plot Plan Showing the Exact Location of Manufacturing Processes and Outlets for Airborne Emissions. Relate All Flows to the Flow Diagram.
See Dwg. No. SRP-L1-A-0
- E. An 8½"x 11" Plot Plan Showing the Exact Location of the Establishment, and Points of Airborne Emissions In Relation to the Surrounding Area, Residences and Other Permanent Structures and Roadways.
See Dwg. No. SRP-L2-A-0
- F. Attach All Scientific, Engineering, and Technical Material, Reports, Publications, Journals, and Other Competent Relevant Information Describing the Theory and Application of the Requested Best Available Control Technology.

B. Heat Rate 11,734 BTU/KW-HR. (Higher Heating Value)

1 KW - HR = 3413 BTU

$$\frac{3413}{11,734} = 29\%$$

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Principal Contaminants

Air pollution has been a product of man's progress since his earliest days on this continent. However, this has been of little concern until the present day when suddenly the cry is to "end all pollution." Air pollution is usually the unintentional result of some activity which emits undesirable substances into the air in either one or a combination of the following physical states:

(1) liquid or solid particles capable of remaining air-borne either permanently or for significantly long periods of time, or (2) gaseous contaminants which expand and mix with the gases of the atmosphere. The diameter of contaminant particles emitted from man-made sources varies greatly in size, from about 1000 microns (near the size of raindrops), to particles substantially less than one micron.

Particulates are considered to be particles generally larger than 50 microns, at which size they settle out of the atmosphere. Aerosols are usually particulates which range in size from 50 microns to something less than 0.01 microns. Most aerosols are considered to be less than 1 micron in diameter. The gases significant in air pollution represent a wide range of organic and inorganic compounds, as shown in Figure 1.

Power generating plants have been considered to be one of the major polluters of the environment but they actually account for approximately

one-eighth of the total man-made air pollution within the United States. Gas turbines now used for power generation contribute an insignificant amount of this contamination. The principal contaminants emitted from gas turbines operating on distillate fuel are unburned hydrocarbons, carbon monoxide, oxides of nitrogen, sulfur dioxide, smoke and particulates. The magnitude of emissions from gas turbines varies with the operating power of the unit. Carbon monoxide and unburned hydrocarbons are only significant at starting and at low power operation such as idle, whereas oxides of nitrogen, smoke, particulates and sulfur dioxide become more significant at peak power.

The presence of carbon monoxide and unburned hydrocarbons at low power levels is primarily due to lower combustion efficiency that might be caused by poor fuel atomization, poor mixing of fuel and air or an inadequate zone burning rate. Oxides of nitrogen (NOx) formations are fixed primarily by the rate of formation and residence time in the hot reaction zones of the combustor. Smoke is formed by carbon generated in a rich primary combustion zone or through quenching in the secondary burning zone. Particulate matter is a function of the fuel quality being consumed. Sulfur dioxide is fixed by the sulfur content in the distillate fuel being burned.

MAJOR CLASSES OF AIR CONTAMINANTS	SUBCLASSES OF AIR CONTAMINANTS	TYPICAL MEMBERS OF SUBCLASSES
Organic Gases	Hydrocarbons	Hexane, Benzene, Ethylene, Methane, Butane, Butadiene, Formaldehyde, Acetone.
	Aldehydes and Ketones	Chlorinated Hydrocarbons, Alcohols.
	Other Organics	Nitrogen Dioxide, Nitric Oxide.
Inorganic Gases	Oxides of Nitrogen	Sulfur Dioxide, Sulfur Trioxide.
	Oxides of Sulfur	Carbon Monoxide.
	Carbon Monoxide	Hydrogen Sulfide, Ammonia, Chlorine.
	Other Inorganics	Dusts, Smoke, Fumes.
Aerosols	Solid Particulate Matter	Oil Mists, Entrained Liquid Droplets.
	Liquid Particulate	

Figure 1

Diffusion of Pollutants

After the pollutants have been released it is necessary to determine how they are transported to a measuring instrument or receptor, and in what concentrations they arrive.

When a concentrated puff of pollutant is released from a source, it tends to expand due to the dynamic action of the atmosphere, and as the same amount of pollutant is now contained in a bigger volume of air, the concentration is decreased. This process of moving from a higher to a lower concentration is the process of diffusion and is accomplished within the atmosphere mainly by two agents, the wind speed and the turbulent motion of the air. The wind speed acts directly to reduce concentration as the effluent leaves the stack, that is, doubling the wind speed will halve the concentrations. Turbulence is generated primarily by the structure of the atmospheric temperature variation with height, and wind flow over surface roughness that acts to mix the pollutant with the ambient air. Source measurements can be made at existing sites whereas a mathematical dispersion model is used to estimate concentrations for future installations.

The most widely used model represents diffusion of the plume as a

two phase problem. The first phase is the initial rise of the plume by virtue of its kinetic and thermal energy. The second phase is its diffusion downwind with an assumed vertical and horizontal distribution of concentration based on statistical reasoning.

Expressions defining the concentrations of pollutants have been established by several workers; TPM utilizes formulae for dispersion estimates (under varied atmospheric conditions) that have been compiled by the Environmental Protection Agency.

Regulatory Standards

It should be noted that the EPA has not, as of this date, provided air pollution regulations specifically for gas turbines.

Some states have used the EPA steam regulations as a guideline in establishing gas turbine exhaust emission standards.

Figure 2 lists the environmental standards most well known i.e., Los Angeles Rule 67, San Diego Rule 68 and the EPA Steam Regulations.

The FT4 gas turbine emission control program being conducted by TPM has had a goal of compliance with Los Angeles County Air Pollution Control District (LACAPCD) Rule 67 under all power conditions.

	Requirements					
	LACAPCD Rule 67		SDAPCD Rule 68		EPA Steam Reg.	
	Gas	Liquid	Gas	Liquid	Gas	Liquid
NOx - Lb/Hr	140	140				
NOx - Lb/MBTU					0.2	0.3
NOx - PPM Corr. 3% O ₂			125	225		
Smoke - Ringelmann		1.0		1.0		1.0
SO ₂ - Lb/Hr 0.3% S Fuel		200		200		
SO ₂ - Lb/MBTU						.8
Part. - Lb/Hr		10		10		
Part. - Lb/MBTU						0.1

Figure 2

MAXIMUM PERMISSIBLE NITROGEN OXIDE EMISSIONS

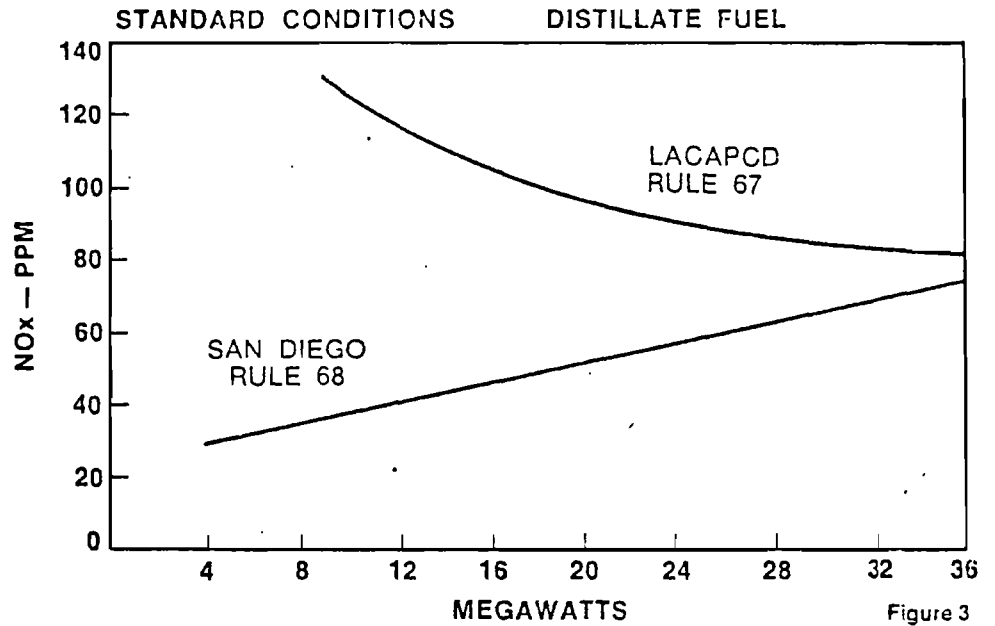


Figure 3

Figure 3 shows the maximum allowable NOx emission (in parts per million) as a function of power output for LACAPCD Rule 67 and San Diego Rule 68.

FT4 Smoke Reduction

In 1969, production was started on a smoke reduction burner can. The new burner can included the use of 1) swirl cups and vanes which surround the six fuel nozzles of each of the eight combustion chambers. Swirl is imparted to the air entering the chamber to improve fuel atomization in the fuel spray pattern;

2) nozzle nuts with tangential air cooling slots to improve fuel atomization; 3) airflow distribution into the burner charged through a series of holes in the head to lean the fuel-air ratio in the primary combustion zone. Figure 4 shows the construction of the smoke-reducing burner can.

The initial goal was to reduce the visible emission from the FT4 gas turbine to a Von Brand Reflectance level of 95 or better which is acceptable to all known air pollution codes.

FT4 SMOKE REDUCING BURNER CAN

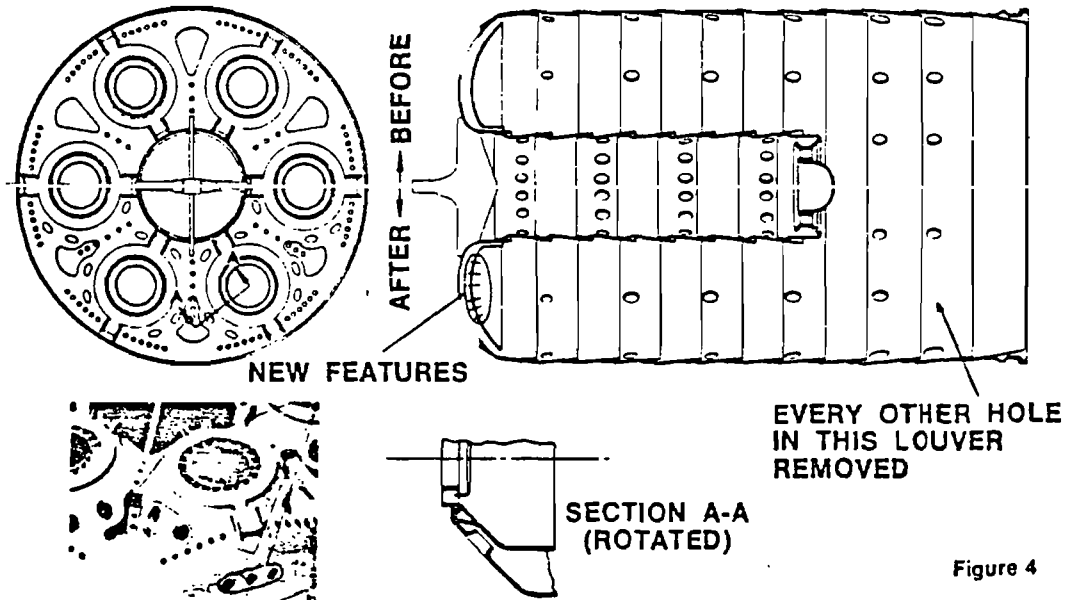


Figure 4

Von Brand Reflectance, Bacharach Smoke Number, and Ringelmann Numbers are different terms used to describe smoke from exhaust stacks. Figure 5 shows the Exhaust Smoke Measurement comparisons between Von Brand Reflectance, Bacharach and Ringelmann. Comparison of Von Brand Reflectance Numbers to visual observations is also shown.

The Von Brand Reflectance is most often used by TPM since it has been accepted by the industry as the most accurate method of determining smoke. A Von Brand instrument collects samples of particulate matter and aerosols on a continuous moving filter paper tape for subsequent analysis. Exhaust gas under test is sampled at a uniform rate by means of a probe positioned in the gas stream at a point of approximate average

flow with the gas pulled thru the filter tape by means of a motor-driven pump or other vacuum source. Evaluation of the smoke stain is accomplished with a Photovolt Reflectometer which compares the reflectance of the smoke stain to a clean piece of filter tape. Clean is one hundred while a stain would read an amount less than 100.

The Bacharach Smoke Number, used by some power companies and state agencies, is obtained by drawing a specific volume of gas from the exhaust thru a spot filter over a normal period of approximately two minutes. The spot is then classified by comparing it with the Bacharach Smoke Scale which has ten standard graduated spots from 0 to 9, white to black.

EXHAUST SMOKE MEASUREMENT COMPARISONS

Von Brand Reflectance At 0.216 SCFM	Bacharach	Ringelmann	Color
100	0	0	Clear
99	1		
97	2		
94	3		
89	4		
85		1	
83	5		
75	6	2	
66	7		
60		3	
56	8		
45	9		
40		4	
20		5	Black

The following table can be used as a guide for comparing Von Brand Reflectance numbers to visual observations.

Appearance	Von Brand Reflectance Numbers
Clean Air	100
Clear - Heat Waves	95
Heat Waves with Faint Wisps	93
Slightly Visible	90
Visible Emission	85
Darker Smoke - Becoming Objectionable	80
Dark Smoke	75
Objectionable Smoke	70

Figure 5

The third method utilizes Ringelmann Numbers which are based on visual observation and is therefore quite subjective. It is expressed in degree of blackness in numbers from 0 to 5, with each number representing a 20% difference in opacity from clean to black. Here again interpolation can be made between numbers. This method has been used extensively by federal and state air pollution control agencies.

TPM is currently conducting a program to reduce further the smoke emission level of FT4 engines while burning distillate fuel by improving the fuel nozzles. This includes the use of aerating nozzles that atomize the fuel through the use of turbine compressor air introduced into the fuel spray at the nozzle outlet.

It is anticipated that these improved nozzles, which will be available in 1973 production gas turbines, will meet all known regulations. The expected smoke level will exceed Ringelmann No. 0.5 or Von Brand Reflectance No. 95. It should also be noted that the type of fuel used affects the smoke level as illustrated by Figure 6.

Sulphur Oxides

Sulphur oxides in exhaust gases,

(chiefly sulphur dioxide, SO_2 , with a trace of sulphur trioxide, SO_3), result from oxidation of essentially all of the sulphur in the fuel being burned. The higher the sulphur content, the more SO_x produced. The high temperatures and flows encountered in gas turbine exhausts make SO_2 removal impractical. The only economical way to limit SO_2 is through the use of low sulphur content fuels.

SO_2 in sufficient concentration is known to be irritating to eyes and skin and is purported to contribute to respiratory disorders. There is some disagreement among experts, as to whether SO_2 is harmful or beneficial to plant life over a long term.

Because of the irritating effects on humans, regulatory agencies will be increasingly vigilant in measuring SO_2 levels in the ambient air. In order to minimize the ambient concentrations, the EPA has established SO_2 limits for steam power plants of 0.8 pounds per million BTU of fuel input. Most gas turbine liquid fuels contain less than 0.5% sulphur, which will produce less than 0.5 pounds per million BTU SO_2 .

SO_2 can be measured by one of several batch sampling systems, such as the "West-Goeke" method, which uses a self-contained automatic chemical process to determine and read out SO_2 concentrations.

EFFECT OF FUEL TYPE ON SMOKE LEVELS — FT4C ENGINE

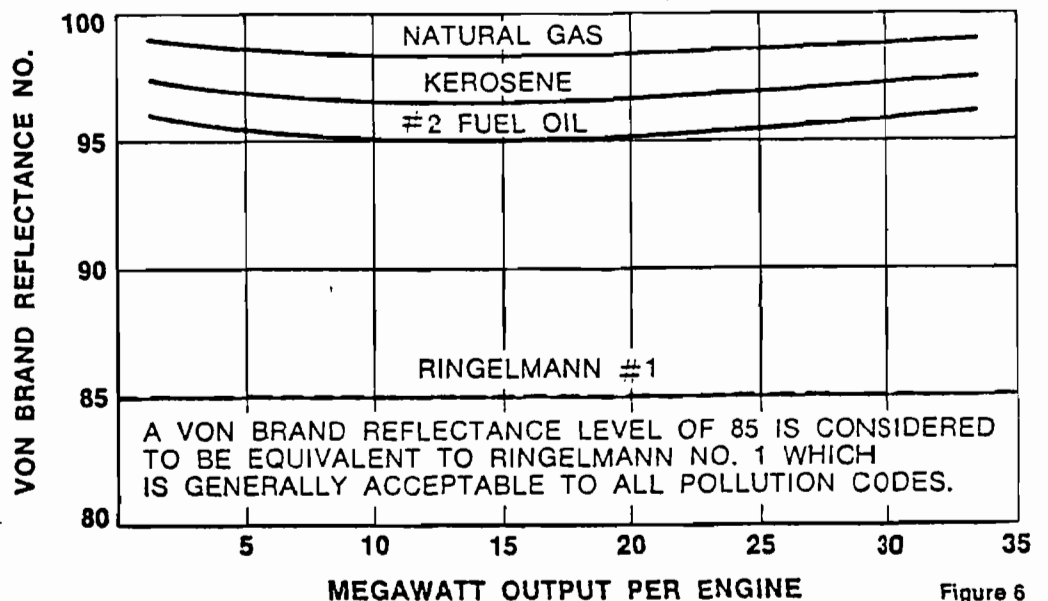


Figure 6

Particulates

Exhaust particulates are generally defined as any solids or condensibles, other than water, in the exhaust stream. In gas turbines burning liquid fuel, particulate emissions usually consist of dirt carried in by the inlet air; metallic ash from fuel contaminants; carbon from incomplete combustion; and condensible sulphur compounds, mostly H_2SO_3 . The particle size and quantity will vary with air and fuel quality.

Gas exhaust particulates can be reduced by filtering the gas turbine inlet air, and by using fuels with low metal and sulphur levels. Further reduction is possible through improved combustor design to minimize unburned hydrocarbons.

Both LACAPCD Rule 67 and SDAPCD Rule 68 limit particulate emission to 10 pounds per hour. The EPA guidelines for steam plants, which many states are applying to all stationary power plants, has a limit of 0.1 pounds per million BTU of energy input. TPM FT4 gas turbines currently in service produce particulate levels of approximately 0.09 lb/MBTU.

Particulates are normally measured by taking a sample of the gas by means of a vacuum probe, passing it through either liquid baths or dry filter pads, and weighing the residue.

Oxides of Nitrogen

Combustion research has shown that oxides of nitrogen (NOx) levels

are fixed primarily by the rate of formation and residence time in the hot reaction zones of the combustor. Factors controlling the final NOx emission levels are:

1. Temperature in both the combustion reaction and dilution zones.
2. Residence times in both zones.
3. Mixing of fuel, air and combustion products.
4. Fuel vaporization.
5. Combustor inlet temperature and pressure.

It has been demonstrated that slow mixing, in conjunction with rich or heterogeneous mixtures, leads to high combustion temperatures and therefore high NOx levels.

A NOx reduction program was initiated for the FT4 gas turbine in early 1971 with a goal to meet the requirements of LACAPCD Rule 67.

A three-prong approach was used in order to accomplish this goal. This included 1) burner rig tests to verify burner design for obtaining the desired emission reduction, 2) flame rig tests for applied research in determining combustion characteristics, and 3) mathematical models or analytical prediction for burner modifications.

It was determined that water or steam injected directly into the primary zone of combustion served to reduce the flame temperature and promote mixing. Burner rig tests confirmed this reduction (Figure 7).

FT4 BURNER RIG RESULTS WITH WATER INJECTION

WATER OR STEAM / FUEL RATIO = 1

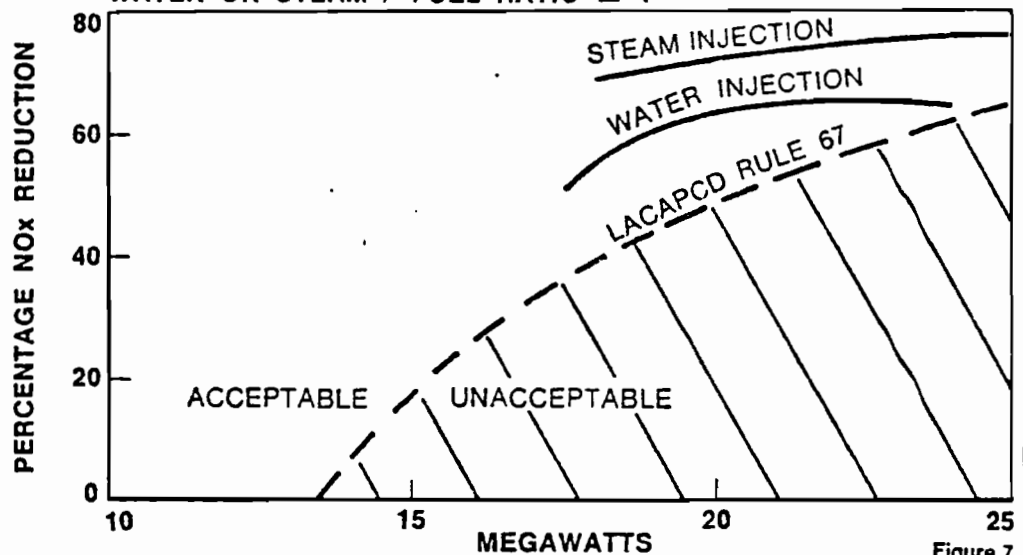


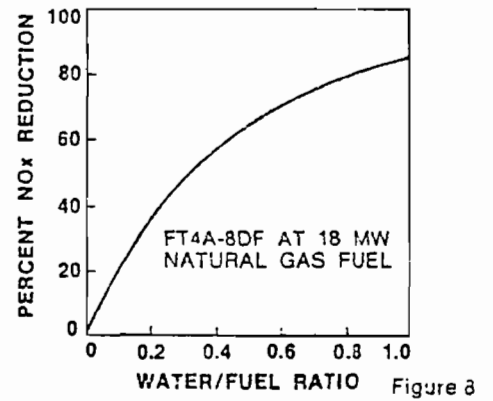
Figure 7

The test results showed a 65% NO_x reduction while injecting water into the chamber and a 75% reduction while injecting steam. Steam injection was found to be more effective in reducing NO_x than water injection on a pound for pound basis, in spite of the greater potential thermal effect of water. The latent heat of vaporization of water is not fully realized because of poor mixing and the slow vaporization rate of the water relative to fuel vaporization and combustion times.

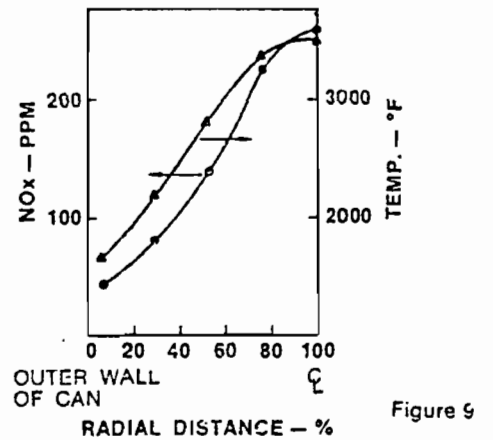
The fact that water injection reduced NO_x emission from gas turbines was further confirmed through full scale engine testing at a TPM field installation in southern California burning natural gas. The water flow rates were varied. NO_x reductions were recorded, and the results are plotted in Figure 8.

Probing within a standard combustion chamber determined temperature and NO_x formation in the can at various stations along its axis. Figure 9 shows the temperatures and NO_x measured across the chamber in the primary flame zone. This supports the theory that NO_x formation is primarily a function of temperature and residence time. Fifty percent of NO_x formation occurred within 0.5 milliseconds after combustion and production was terminated by 3 milliseconds. Probing the same combustion chamber with steam injected into the primary zone shows a reduction of peak temperatures as shown in Figure 10. NO_x levels were significantly reduced by steam injection since the peak temperatures were reduced below the level required for high NO_x formation.

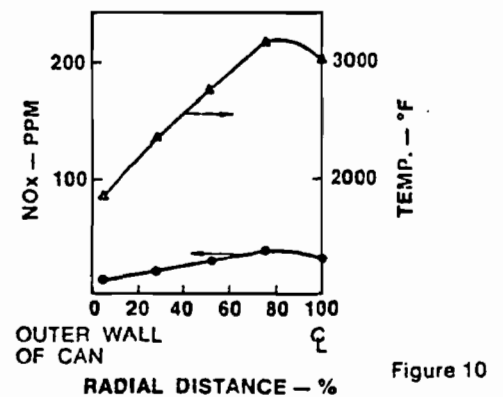
**H₂O INJECTION
ENGINE DEMONSTRATED REDUCTION**



**FT4 BURNER CAN TEMPERATURE & NO_x TRAVERSE
EIGHT INCHES DOWNSTREAM OF NOZZLE**



**FT4 BURNER CAN TEMPERATURE & NO_x TRAVERSE
EIGHT INCHES DOWNSTREAM OF NOZZLE
STEAM INJECTION - 1.4 LBS / LBS FUEL**



FT4 BURNER RIG NEW COMBUSTION PROGRAM RESULTS

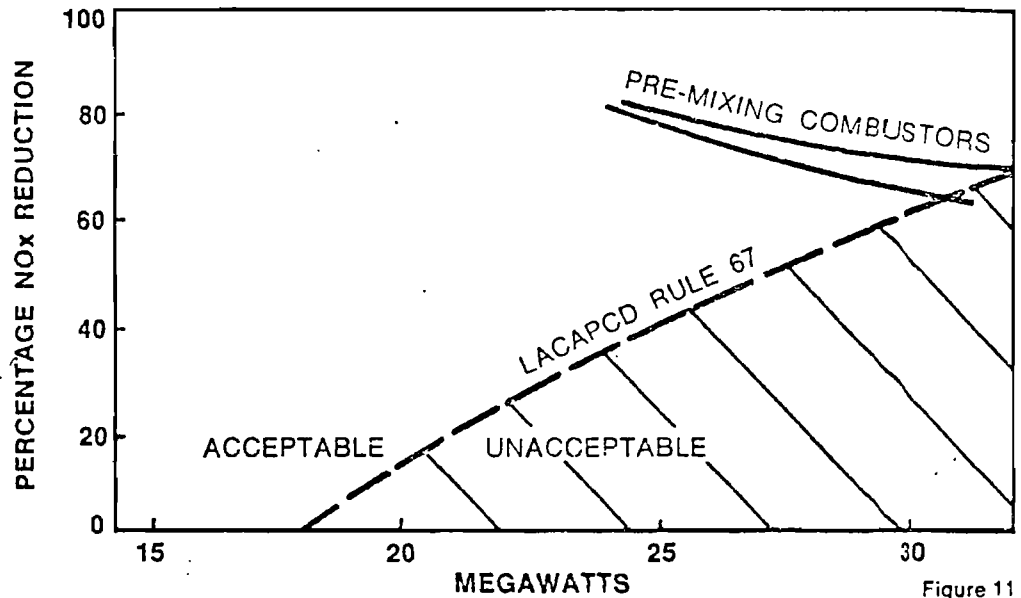


Figure 11

To eliminate the requirement for water or steam injection a new approach is being investigated through premixing and prevaporizing the fuel prior to combustion. Combustion rig tests using these techniques shown in Figure 11 have demonstrated that NOx emission levels are substantially below Rule 67 requirements. This "dry fix" enables the utility to meet existing and anticipated NOx requirements and at the same time retain the gas

turbine remote siting capability by precluding the need for a major demineralized water or steam source. Plans are being implemented to make "dry fix" burner cans available in 1974 production engines.

Conversion Equations

Sometimes it is convenient to express NOx exhaust emissions in parts per million (ppm), pounds per hour (#/Hr.) or pounds per million BTU (#/10⁶BTU). The three equations shown in Figure 12 may be useful.

To find NOx (ppm)

$$\text{NOx (ppm)} = \frac{\text{NOx (\#/Hr)}}{\text{Wg (\#/Hr)}} \times \frac{\text{MOL WT AIR}}{\text{MOL WT NOx}} =$$

$$\frac{\text{NOx (\#/10}^6\text{BTU)}}{\text{Wg (\#/Hr)}} \times \frac{\text{HR (BTU/KwHr)}}{10^6} \times \text{OUTPUT (Kw)} \times \frac{\text{MOL WT Air}}{\text{MOL WT NOx}}$$

To find NOx (#/Hr)

$$\text{NOx (\#/Hr)} = \text{NOx (ppm)} \times \frac{\text{MOL WT NOx}}{\text{MOL WT Air}} \times \text{Wg (\#/Hr)} =$$

$$\frac{\text{NOx (\#)} }{10^6\text{BTU}} \times \text{HR (BTU/KwHr)} \times \text{OUTPUT (Kw)} \times \frac{\text{MOL WT NOx}}{\text{MOL WT Air}}$$

To find NOx (#/10⁶BTU)

$$\text{NOx (\#/10}^6\text{BTU)} = \frac{\text{NOx (\#/Hr)} \times 10^6}{\text{Hr (BTU/KwHr)} \times \text{OUTPUT (Kw)}} =$$

$$\frac{\text{NOx (ppm)}}{\text{Hr (BTU/KwHr)}} \times \frac{\text{MOL WT NOx}}{\text{MOL WT Air}} \times \frac{\text{Wg (\#/Hr)} \times 10^6}{\text{OUTPUT (Kw)}}$$

NOx is calculated as NO₂, Mol Wt = 46; Mol Wt Air = 29

Figure 12

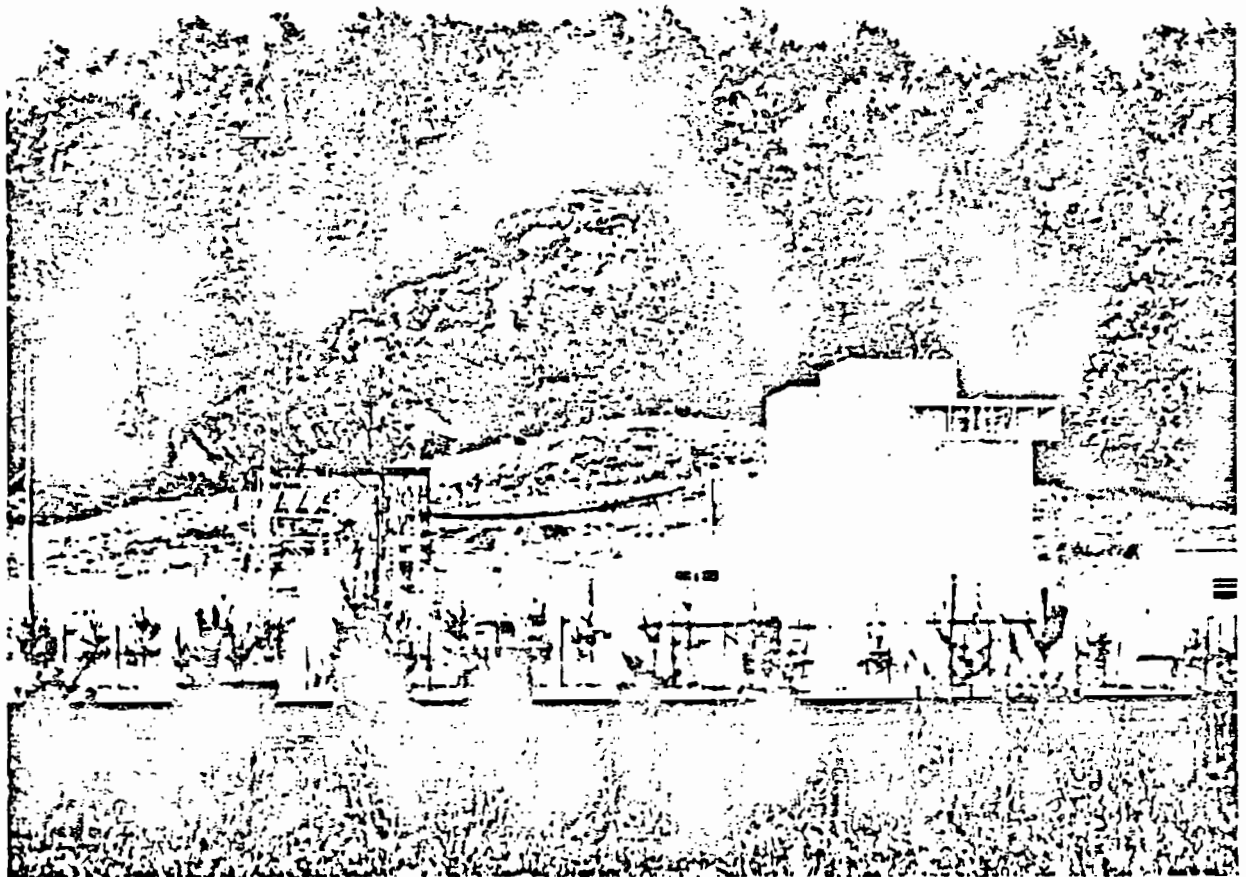
Summary

TPM recognizes the importance of clean air and will continue its intensive emission reduction program to keep abreast of and meet federal, state, and local regulatory standards. Actual rig and engine tests have demonstrated that the FT4C-1 engine can limit NOx emissions to meet known regulations by using water injection, steam injection, or the "dry fix".

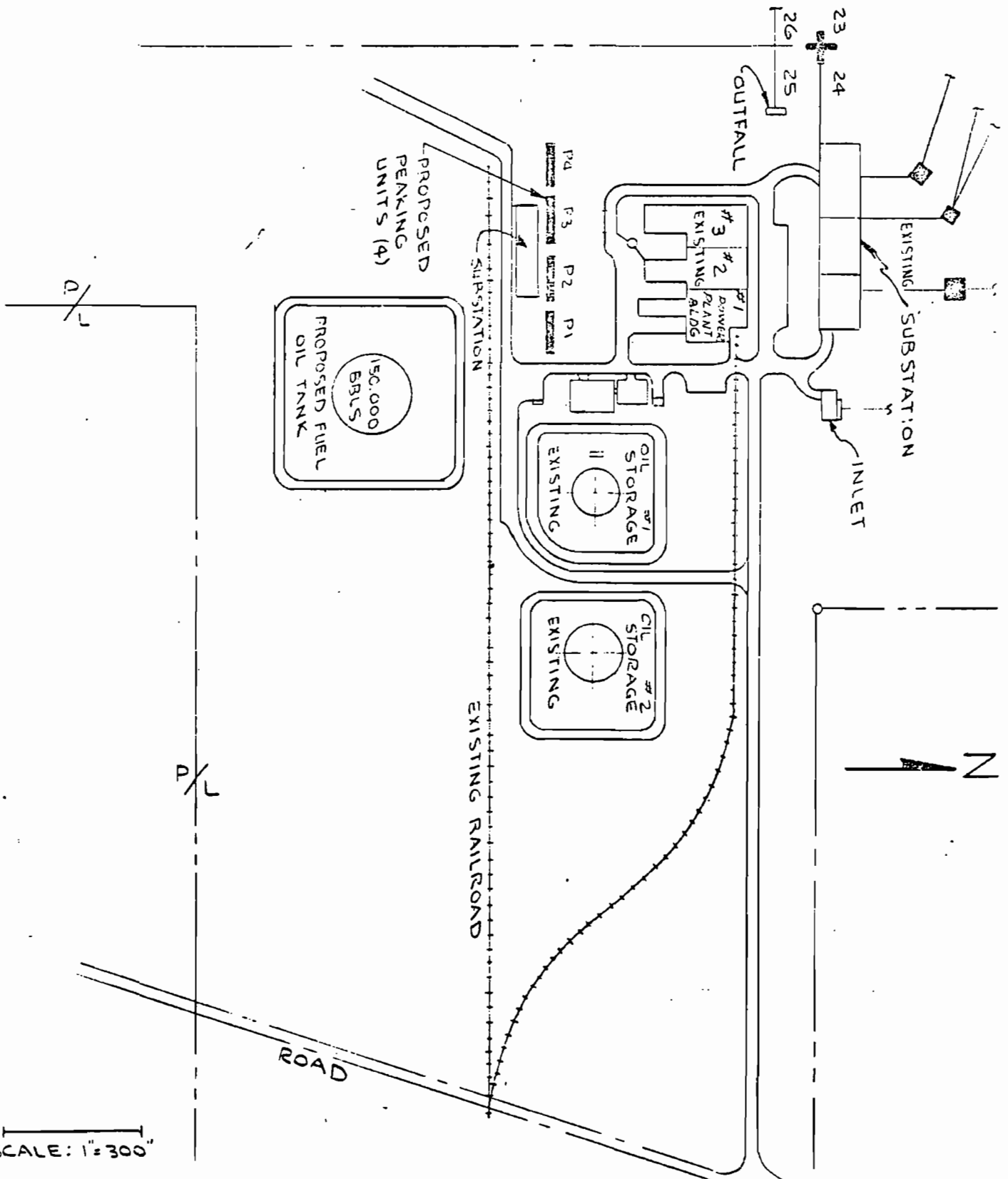
The water or steam injection systems require provision of a demineralized water or steam source which is an added item of cost in most installations. Although TPM is prepared to provide such systems

where they make economic sense, the "dry fix" approach appears to be the more desirable. The "dry fix" burner cans enable the customers to meet known NOx emission requirements without additional equipment or expense. This is particularly important in areas where water is scarce or unavailable. A demineralized water or steam source, which must be available for combined cycle plants, does not become a necessity for a TPM simple cycle gas turbine unit. This offers the customer maximum equipment selection flexibility when considering a TPM installation.

Typical TPM simple-cycle FT4 Twin Pac installation.



FLORIDA POWER CORPORATION
SYSTEM ENGINEERING DEPARTMENT



REVISIONS	
NO.	DATE

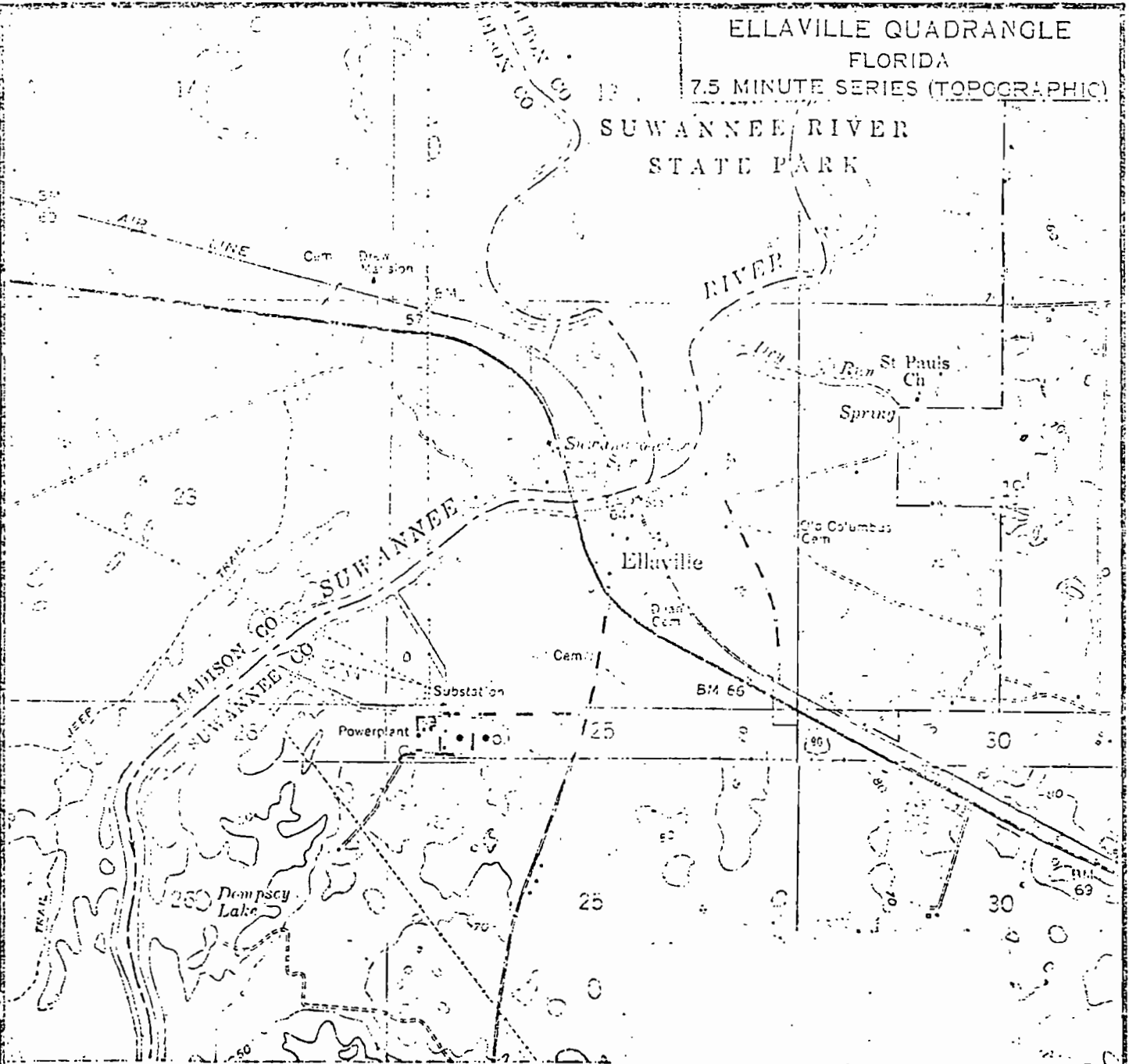
SITE PLAN FOR
PROPOSED SUWANNEE
RIVER PEAKERS

DRAWN BY MWP
DATE 2-2-78
CHECKED R. O. [Signature]
APPROVED [Signature]
SCALE 1" = 300'

SRP-LI-A-0

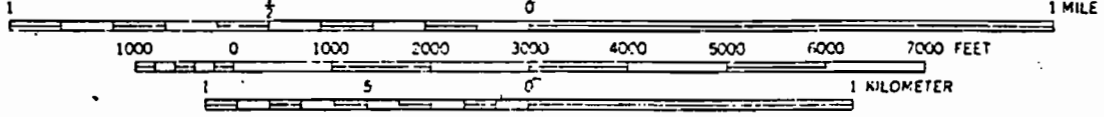
ELLAVILLE QUADRANGLE
 FLORIDA
 7.5 MINUTE SERIES (TOPOGRAPHIC)

SUWANNEE RIVER
 STATE PARK



TRUE NORTH
 MAGNETIC NORTH

SCALE 1:24000



APPROXIMATE MEAN
 DECLINATION, 1959

CONTOUR INTERVAL 10 FEET
 DATUM IS MEAN SEA LEVEL

NO.	DATE	REVISION	BY	CK.	APP.

GENERAL AREA
 LOCATION MAP

PROJECT SUWANNEE R. GAS TURB. UNITS
 FLORIDA POWER CORPORATION
 ST. PETERSBURG, FLORIDA

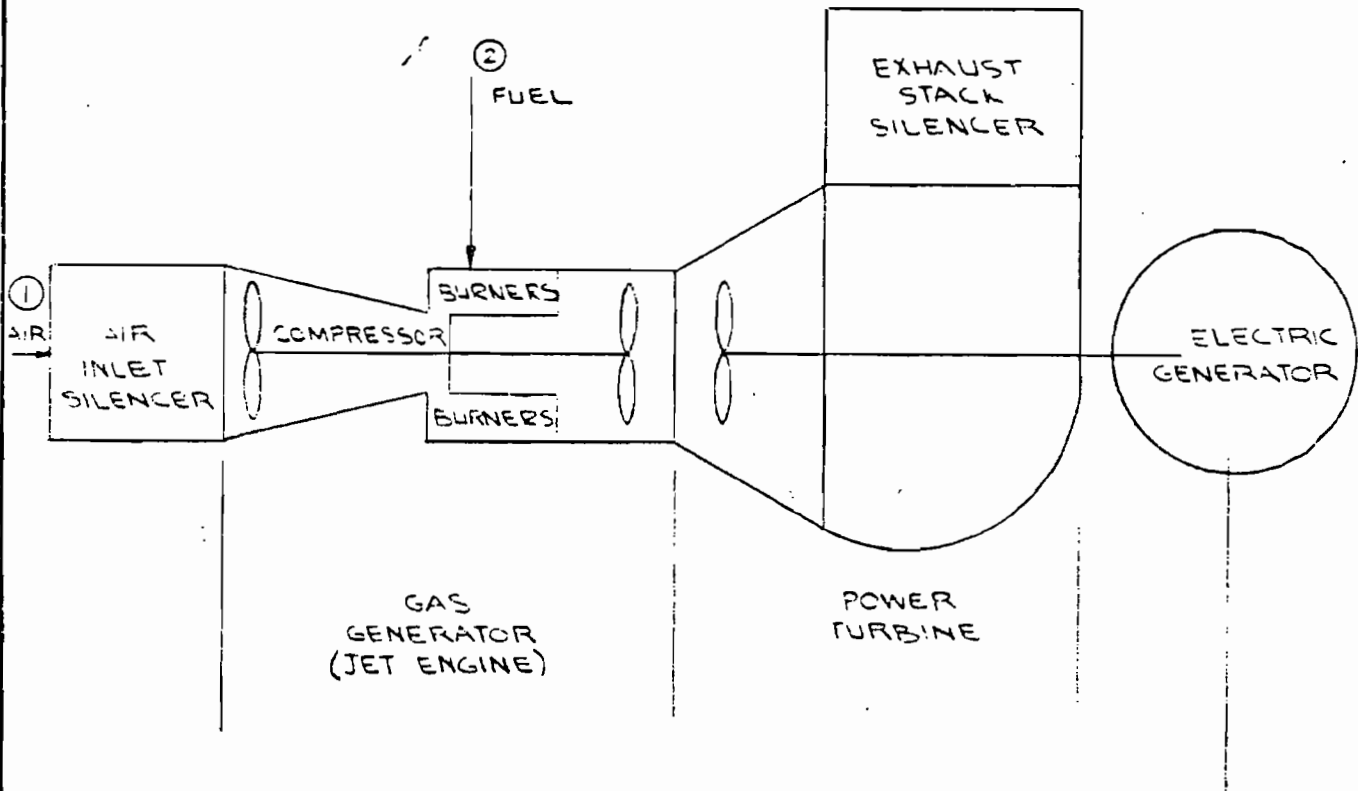
DATE 2-2-78 SCALE AS NOTED BY MWP CK. APP.

DRAWING NO. SRP-L2 - A-0

FLORIDA POWER CORPORATION
SYSTEM ENGINEERING DEPARTMENT

NOTE: EACH UNIT HAS 2
EXHAUST STACKS

③
EMMISSION TO
ATMOSPHERE



NOTE: EACH UNIT CONSISTS OF
1 ELECTRIC GENERATOR
AND 2 JET ENGINES

NOTE: UNIT IS SYMETRICAL
ABOUT E

REVISIONS	
NO.	DATE

FLOW DIAGRAM
SUWANNEE RIVER PEAKERS

DRAWN BY [Signature]
DATE 2/6/75
CHECKED _____
APPROVED _____
SCALE 1" = 1'

DWG NO. SRP-L3-A-0

DESCRIPTION OF FLORIDA POWER CORPORATION
GAS TURBINE GENERATING UNITS TO BE LOCATED
AT THE COMPANY SUWANNEE RIVER POWER PLANT SITE

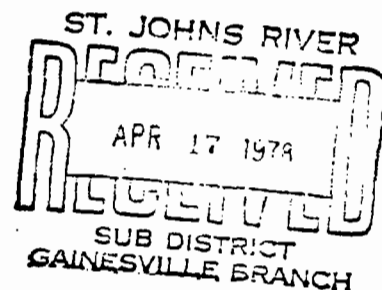
Four (4) 63,000 KW gas turbine electric generating units are intended to be constructed for Florida Power Corporation. The units are planned for installation at the Florida Power Corporation Suwannee River Power Plant site. The units are scheduled for commercial operation in October 1980, and will be known as Suwannee River Peaking Units 1 through 4.

The gas turbine electric generating units are individually housed and are completely automated facilities. The units will be operated by remote control and no water is utilized for cooling purposes.

The plants are to be used for peaking purposes (intermittent operation) and will normally be run in the daytime and early evening during periods of peak electrical load. These units will be run at night only during emergencies.

At the peak power level of 63,000 KW, occurring at an ambient air temperature of 59°F, each unit will burn approximately 632 pounds of liquid fuel per minute. The exhaust gas flow at this rating will be 1,255,500 ACFM at an approximate temperature of 726°F. Clean burning fuel which will have a maximum sulfur content of 0.5% will be used. The output of the gas turbines will vary with the ambient air temperature and the maximum plant electrical output will vary accordingly.

Since the gas turbines utilize low sulfur fuel oil, causing an essentially clear exhaust discharge, the process is considered to be an extremely low pollution source. The smoke density is less than a Ringleman #1 during all modes of operation and the visible emissions shall be less than 20% opacity.



WET METHOD

The present day available (state of the art) control device for reducing NO_x emissions formed in combustion turbines is injection of water with the fuel in the gas turbine burner chambers. Various types of burners are used by the major manufacturers and therefore the quantity of water injected will vary according to the particular manufacturer. In general the amount of water injection required to meet the allowable emission level (75 PPM NO_x by volume) will run from 50% to 100% of the total weight of fuel burned.

The water injection cools the flame which lowers the temperature which is the mechanism by which NO_x is formed in the combustion process.

To prevent high temperature corrosion of the turbine blades, only demineralized water can be used for the water injection (with Sodium content of 1 PPM or less). There is an efficiency loss in the combustion turbine due to water injection as follows:

Assume 1# of water need per 1# of fuel fired.

$$\Delta h \left(\begin{array}{l} \text{Heat required to vaporize 1\# of water at } 70^{\circ}\text{F} \\ \text{to } 726^{\circ}\text{F exhaust temperature} \end{array} \right) = 1,356 \text{ BTU/\#}$$

Heating Value of fuel = 19,500 BTU/#

$$\text{Gross Loss in Thermal Efficiency} = \frac{\Delta h \text{ injection water}}{19,500} = \frac{1,356}{19,500} = 6.95\%$$

DRY METHOD

As an alternate, most manufacturers are developing burner chambers that will reduce NO_x emissions to the allowable level by staging the fuel combustion in various zones of the burner chambers to lower the overall burner temperatures and NO_x formation conditions. Presently this type of control is not available commercially for a gas turbine plant, but it is possible that due to rapid development, the "dry" NO_x burner chambers will be available at the time or soon after the new generating units will be operational (October 1980)..

There is no loss in thermal efficiency when using the dry type emission control method and consequently it is the preferred method.

SOCIAL ECONOMIC IMPACT

A fundamental social economic benefit is derived from the adequacy of electric supply to meet society's demand for energy. The proposed installation of 200 MW of gas turbine capability at Suwannee River Plant is part of a strategic generation expansion plan that has been evaluated as the economic optimum choice from a set of alternative plans. This selected strategy considers state wide coordination, including purchase power agreements and joint venture projects.

The construction of a four unit project will employ a peak construction work force and supervisory staff of approximately 125 people. Capitalized construction costs of each individual unit is estimated at approximately \$10.5 million, including state sales taxes of approximately \$275,000. Construction payroll will impact the local community with expected average monthly payroll for the project of \$100,000 over the 18 month period. This represents a benefit to employment and the local economy relative to the subsistence needs of these local and transient workers. In addition to labor payroll, construction materials and supplies will be purchased from local businesses. Additional sales taxes will be derived from partial expenditure of this payroll by the construction labor force.

The unit will become operational in October 1980. The social economic impact of the operation of the plant can be best analyzed on a total project basis, as opposed to individual unit price and the resulting economic benefit could theoretically be allocated in proportionate shares to each unit.

This project will create an estimated eleven new permanent jobs to operate, maintain and manage the facilities, with an estimated new annual payroll of \$275,000. These people will be residents of the local area and their income will stimulate the local economy, by the construction of homes and the consumption of goods and services to meet their living needs. State sales taxes and local property taxes will also be impacted by the presence of these plant personnel.

Production of energy from this plant will represent a vital part of the state's energy needs during peak load requirements. The role of these facilities in the overall configuration of Florida Power's generation plans is expected not to exceed 1500 hours per year, to supply peak load requirements. The characteristic low capital cost of these facilities, in spite of their higher fuel costs, results in an economic contribution to the energy supply for our system and for the state. The fuel oil consumed by these units is minimal because of the limited hours a year of operation during peak load requirements only.

The supply of fuel and the supply of outside materials and services to operate and maintain these facilities represents additional social economic benefit. The social economic costs of the presence of these facilities is represented by the added stress on socio-economic systems, including traffic congestion and other problems associated with higher population density - particularly during the construction phase.

ASSESSMENT OF THE ENVIRONMENTAL IMPACT OF THE SOURCES

The site selected for the proposed combustion turbines is immediately adjacent to the existing fossil-fueled units of the Suwannee River Generating Facility. Because these new units will be built on already cleared and partially compacted land, no impact to natural vegetation or wildlife is anticipated. No alteration to the local hydrology is expected, and storm water runoff patterns will not be altered.

Any waste waters generated will be conveyed to the existing evaporation/percolation ponds. The noise generated during construction should be attenuated before it reaches the property boundaries.

The only potential environmental impact is alteration of the ambient air quality. This impact will be discussed in the Prevention of Significant Deterioration permit application.

ATTACHMENT B
STUDY GROUP RECOMMENDATIONS

State of Florida


DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices
And/Or To Other Than The Addressee

To: _____	Loctn.: _____
To: _____	Loctn.: _____
To: _____	Loctn.: _____
From: _____	Date: _____

TO: Al Townsend, Bob Kappelmann, Steve Smallwood
and Frank Darabi

FROM: J. P. Subramani 

DATE: May 22, 1978

SUBJECT: Florida Power Corporation BACT application for
4 stationary gas turbines to be constructed
at the Suwannee River Plant site, Suwannee
County, Florida.

The above referenced source will be considered for BACT determination when the BACT rule becomes effective about June 9, 1978.

You have been selected to participate in the BACT determination for this source. Enclosed for your review and evaluation is the complete application for BACT determination.

Your responding by June 16, 1978 will be appreciated.

JPS/VM/es

Enclosure

Walt Staines

State of Florida

DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee	
To: _____	Loctn.: _____
To: _____	Loctn.: _____
To: _____	Loctn.: _____
From: _____	Date: _____

TO: J.P. Subramani

FROM: Albert W. Townsend *awt*

DATE: June 19, 1978

SUBJECT: Application for Determination of Best Available Control Technology (BACT) for Gas Turbines

The subject application left quite a bit to be desired. No test data was supplied with the package; therefore, there is nothing to base an emission limiting standard on for SO₂ or NO_x emissions.

There was only one (1) method proposed to control SO₂ emissions; i.e., low sulfur fuel. Therefore, based on the application this would have to be considered BACT.

Two (2) methods were proposed for the control of NO_x. One method isn't commercially available; therefore, the wet method would have to be considered BACT.

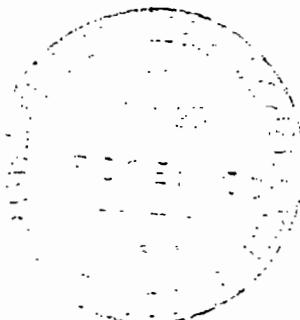
I feel that all future BACT applications should be screened to insure that there is enough information and alternatives so that the reviewing engineer will have a choice. For instance, there is more than one way to reduce SO₂ emissions besides low sulfur fuel; i.e., limestone scrubbing, magnesium-oxide scrubbing, Wellman-Lord.

It is a waste of our time to attempt to analyze an incomplete application. It is suggested that no distribution for BACT determination be made until the application is complete and then a complete application should be sent to the appropriate parties.

If you have any questions please contact me, SUNCOM 451-5005.

AWT:fs

cc: Warren G. Strahm



DEPARTMENT OF HEALTH, WELFARE
& BIO-ENVIRONMENTAL SERVICES
Bio-Environmental Services Division
Air and Water Pollution Control



June 23, 1978

Dr. J.P. Subramani, Chief
Bureau of Air Quality Management
2600 Blair Stone Road
Tallahassee, FL. 32301

SUBJECT: BACT APPLICATIONS FOR FLORIDA POWER CORPORATION GAS TURBINES-
SUWANNEE RIVER PLANT SITE

Dear Dr. Subramani:

I have reviewed the above mentioned applications and feel adequate data was not made available to form a sound judgement on what BACT for this type source should be. Specifically, question G9 is critical in finding out in fact how the proposed technology is working in practice. However, the following is offered based on the data supplied by the applicant and our own experience with gas turbines.

BACT should specify an emission rate as well as the equipment and/or procedures used for control. For example, low sulfur fuel is BACT for SO₂ for this source but to be effective, maximum sulfur content must be specified. This is also true with ash content.

Based on current fuel availability, BACT should require a fuel sulfur content of no greater than 0.3%. Ash content should be limited to less than .01% since 0.005% ash in this type fuel is available. Opacity should be limited to 10% or less except for start up. NOx control should be by water or steam injection. Steam should be specified unless a ready source of steam is not available. A water or steam to fuel ratio should be specified as well as a maximum ppm of NOx. Fifty (50) ppm NOx limit is possible at water or steam to fuel ratio of about 1.4. Particulate should



Dr. J.P. Subramani, Chief
June 23, 1978
Page 2

be adequately controlled by specifying sulfur and ash content of the fuel and with a 10% opacity limit.

The above mentioned BACT limits are based on what should be readily available commercially. Even more restrictive limits are possible but the economics of greater cost with a minimal improvement in air quality must be considered.

Again my remarks are based on the data supplied. Deficiencies in the applications are numerous and seriously jeopardize the applicants ability to justify his requested BACT limits. I feel a workshop with the affected parties would be beneficial.

Sincerely,


Robert L. Kappelmann, P.E.
Air Pollution Control Engineer

RLK/dl

12.9.17.2

State of Florida

DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

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TO: J. P. Suhramani

FROM: Steve Smallwood *Steve Smallwood*

DATE: June 14, 1978

SUBJECT: BACT RECOMMENDATION
 Four (4) Stationary Gas Turbines
 Florida Power Company, Suwannee Plant Site
 Suwannee County, Florida

This report provides background information and recommended BACT for four (4) new distillate oil fired, 63 megawatt (each) stationary gas turbines which Florida Power Company (FPC) proposes to install at their Suwannee River plant to provide peaking power.

Summary -----	1
Discussion-----	2
BACT-----	7
Recommended	
Emission Standards-----	8
Comments-----	14

SUMMARY

There are no emission limiting standards currently included in the Florida Air Pollution Control Regulations (17-2) which directly apply to stationary gas turbines. The rule therefore requires that the allowable emission standard be based on a determination of emission level achievable through the application of Best Available Control Technology (BACT).

At the present time the BACT for reducing air pollutant emissions resulting from the operation of large stationary gas turbines of the type proposed by FPC is the use of water or steam

J. P. Subramani
PAGE TWO
June 14, 1978

injection to control nitrogen oxide (NO₂) emissions, the use of low sulfur fuels to reduce sulfur dioxide (SO₂) emissions, and the use of more efficient fuel combustors (cannisters) to reduce smoke, hydrocarbon (HC) and carbon monoxide (CO) emissions.

Using this technology, NO₂ emissions can be reduced to below 75 ppm corrected to 15% Oxygen (O₂) in the exhaust gas, adjusted for the effects of turbine efficiency, nitrogen content of the fuel, and atmospheric conditions.

SO₂ can be limited to 150 ppm corrected to 15% oxygen by using #2 distillate oil, or to lower levels by using cleaner fuels if they are available.

Smoke, HC, and CO emission can be kept at acceptable levels by requiring the discharge gas to have an opacity of less than 20%, which is achievable.

Background information on FPC's proposed installation is included under DISCUSSION. Supporting information for the BACT recommendation is included under BACT and RECOMMENDED EMISSION STANDARDS. The proposed federal test method for stationary gas turbines is included as an attachment. Notes on several questions concerning FPC's proposal that are not fully answered by the information provided in their BACT application plus notes on several related issues are included under COMMENTS.

DISCUSSION

Florida Power Company plans to install four (4) stationary gas turbines at their Suwannee River Plant site. They propose to fire each unit with a maximum of 37,910 #/hr of distillate fuel oil (6.8 #/gal, 19,494 BTU/lb). Each unit is to be composed of two parallel jet engines, the exhausts from which will drive a power turbine. Each unit (pair of engines plus power turbine) is to be capable of generating 63 megawatts of electrical energy at peak load. Each megawatt-hr. of power output is equivalent to 3,413,000 BTU of energy. Total maximum hourly design peak output is then 215.019 MMBTU resulting from a total heat input of 739 MMBTU: a thermal efficiency or 'heat rate' of 29.1% (215/739) *each unit*

Stationary gas turbines emit nitrogen oxides (NO, NO₂), sulfur dioxide (SO₂), hydrocarbons (HC), carbon monoxide (CO), fine particulate (PM), and smoke. Stationary turbines used for

electrical power production are normally operated at or near rated capacity. They are usually operated for approximately five (5) hours per day to handle peak load electrical demand. Some companies will operate their turbines for short periods of time at no load conditions in anticipation of any rapid surge in power demand. This is referred to as "spinning reserve." The write-up in EPA's "Compilation of Air Pollutant Emission Factors", (AP-42, third edition, August 1977), on stationary gas turbines states that a 'typical' turbine operates 1200 hours per year, for 250 starts, operating 4.8 hours per start. The emission factors (#/hr per rated capacity-megawatts) for stationary gas turbines (AP-42, 3rd edition, section 3.3.1) are based on the following assumed load conditions:

15%	@	zero load (spinning reserve)
2%	@	25% load
2%	@	50% load
2%	@	75% load
60%	@	100% load (rated)
19%	@	125% load (peak)

Based on these conditions and the AP-42 emission factors, each FPC gas turbine would be expected to have the following annual uncontrolled emissions:

	MW (rated) X EF X hr/yr X (T/lb)	=	Tons/yr
NO _x :	50.4 X 9.60 X 1200/2000	=	<u>290</u>
SO ₂ :	50.4 X 0.50 X 1200/2000	=	15
HC:	50.4 X 0.79 X 1200/2000	=	24
CO:	50.4 X 2.18 X 1200/2000	=	66
PM:	50.4 X 0.71 X 1200/2000	=	21

(Note: FPC listed 63 MW* as the peak load in their BACT application. Peak capacity is assumed to be 125% of rated continuous basis: $63 \div 1.25 = 50.4$) The SO₂ emissions will vary directly with the sulfur content of the fuel used. The sulfur content assumed for the emission factor was not specified in AP-42. Typical sulfur content for distillate oil is approximately 0.5% with a maximum of 0.7%.

In their BACT application FPC listed each turbine as operating 1500 hours per year at four hours operation per start for 375 starts per year. These units are to operate daytime and early evening to provide peaking power. FPC estimates the actual

* See COMMENTS - #1

maximum discharge rate for each turbine as follows (from BACT application):

NO _x	:	187.5	Tons per year
SO ₂	:	284	Tons per year
HC	:	6.75	Tons per year
CO	:	64.5	Tons per year
PM	:	28.5	Tons per year

These estimated emissions are to be discharged through a stack listed as having a minimum height of 22 ft. with a cross-sectional area of 130 sq. ft. (rectangular). The exit gas volume is listed at 1,255,500 ACFM at 726° - 800° F for an exit gas speed of 153 FPS. (At the listed exit volumetric flow rate and cross-sectional area the exit gas speed should be 160 FPS).

FPC lists the distillate oil as having a maximum sulfur content of 0.5%. If all sulfur in the fuel is converted to SO₂, the maximum annual SO₂ emissions based on their listed fuel use rate would be:

$$\begin{aligned} \text{Fuel (\#/hr)} \times \% \text{ S/100} \times 2 (\text{SO}_2/\text{S}) \times \text{hr/yr} \div 2000 &= \text{Tons/yr} \\ 37,910 \times 0.005 \times 2 \times 1500/2000 &= 284 \end{aligned}$$

which is in agreement with the FPC SO₂ estimate. The AP-42 emission factor for SO₂ for stationary gas turbines fired with oil is equivalent to burning an oil with a sulfur content of approximately 0.025%. This appears to be a technical or typographical error, and the emission factor should not be used. The FPC estimate is based on maximum sulfur content and continuous peak load operation for 1500 hours per year. Their actual average load can be expected to be in the range of 85-90%, therefore, actual annual SO₂ emissions can be expected to be approximately 200 Ton/yr (assuming 88% average load, and 0.4% average sulfur).

Both the AP-42 and FPC particulate emission estimates appear to be in a reasonable range.

Spinning reserve operation results in inefficient fuel combustion which can increase emissions of unburned carbon particles, hydrocarbons and carbon monoxide. In their BACT application FPC did not specify the percent of time that they expect to operate these units in spinning reserve.

The FPC and AP-42 carbon monoxide estimates are essentially the same, however the FPC hydrocarbon estimate is considerably less than the AP-42 estimate. Hydrocarbons generally will be burned to CO₂, CO, and water before CO is oxidized to CO₂. The amount of hydrocarbons emitted will depend upon the combustion efficiency, which will depend upon how the units are operated and maintained. At low load conditions and/or very low fuel to air ratios, hydrocarbon and CO emission can increase by a factor of 10. The FPC HC and CO estimates suggest that they expect to operate these turbines at moderate fuel to air ratios and at moderate to full load conditions during most of the time they are in operation, but a specific statement to this effect has not been included in the BACT application.

The NO_x emission estimates listed by FPC on their BACT application represent emissions after control. The control technology they propose (water injection to the gas turbine combustion chambers-cannisters) would reduce NO_x emission, but would have little effect on the other air pollutant emissions. The AP-42 emission estimates are for uncontrolled emissions.

US EPA published the results of their investigation of stationary gas turbine emissions in September 1977. In that report "Standards Support and Environmental Impact Statement, Volume 1: Proposed Standards of Performance for Stationary Gas Turbines" (EPA-450/2-77-017a), EPA included a table on page 3-46 of that document that summarized the air pollutant test results of several gas turbines produced by different manufactures. Below is a partial listing of that data for turbines of a size and type (simple cycle turbines) similar to those proposed for the Suwannee River Plant site.

Manufacturer & Engine No.	Type Fuel	Base Load MV	Plume Opacity	#/hr		
				NO ₂	CO	SO ₂
General Electric M57001B	DF-2	59.4	-	371	0	355
M57001C	DF-2	66.2	<10%	531	4	401
Turbodyne 11C	DF-2	51.7 ^k	8%	319	47.2	332
Westinghouse N501B4	DF-2	88.85 ^k	<20%	925	43.9	485

^k - peak rate * at 0.5% sulfur

Assuming that peak rates are about 1.25 times base load rates, the average #/hr of NO₂ per megawatt (base load design) is 8.75 with a standard deviation of 2.9 or 34% of the mean value. This data compares fairly well with the 9.6 #/hr factor listed in AP-42. Therefore FPC is proposing to reduce NO₂ emissions from their new gas turbines by approximately 49%: $(363-187)/363 = 0.485$.

The operation of the four (4) stationary gas turbines at the Suwannee River plant site would result in the following estimated actual annual emissions based on 1500 hr of operation for each turbine, a minimum of spinning reserve operation, the use of 0.3-0.5 % S distillate fuel oil (#1), an average load of 88%, and the uses of water injection to reduce NO₂ emission by approximately 50% from uncontrolled emission levels.

NO ₂	:	140-190 Ton/yr
SO ₂	:	200-270 Ton/yr
HC	:	10-20 Ton/yr
CO	:	50-60 Ton/yr
PM	:	20-30 Ton/yr
Smoke	:	<20% opacity

In the SSEIS document mentioned above, EPA presented the results of some modified diffusion modeling based on the CRSTER single source model. Three modifications were made to the model: 1) Briggs bouyant plume rise model is used to account for the expectation that the maximum ground level concentration will occur at a distance closer in to the source than the distance at which the plume reaches its maximum height; 2) The plume rise height used in the Single Source Model (CRSTER) is 70% of that estimated in (1) above. This is to account for the loss of plume rise observed due to strong wind shear and increased mechanical turbulence due to nearby buildings and the relatively low discharge height of turbine stacks (usually less than 10 meters). 3) The plume height at two building heights down wind of the turbine structure is calculated. If the plume centerline is less than 2.5 times the height of nearby structures, the vertical dispersion parameters are enhanced (increase indicated stability class).

The results of this modeling (Ch. 6 SSEIS document) suggests that the maximum ground level impact of the emissions from each of FPC's four turbines would be as follows:

* 290 (1500/1200) - The AP-42 estimate was based on 1200 hr. operation, the FPC estimate is based on 1500 hr. of operation.

Emissions:		GLC: $\mu\text{g}/\text{m}^3$ for each turbine			
<u>gm/sec</u>		<u>3 hr</u>	<u>8 hr</u>	<u>24 hr</u>	<u>Annual</u>
31.5	NO ₂ :	(250)	-	-	0.3
47.8	SO ₂ :	380	-	110	0.6
1.3	HC :	(10)			
10.8	CO :		0.2*		
4.8	PM :			(10)	(0.1)

* mg/m^3

Note: Numbers in parenthesis were estimated by comparison with other data included in the Table on page 6-22 SSEIS document.

While these estimates should be considered only rough approximations, they do indicate that neither HC, CO or particulate emissions from these turbines can be expected to have a significant impact on the surrounding ambient air quality, if the estimated emission rates are approximately correct.

However NO₂ and SO₂ emissions may have a significant impact.

If all four turbines were operated at the same time, on a windy day, a maximum ground level impact in the range 1200-1500 $\mu\text{g}/\text{m}^3$ SO₂ could possibly occur within one half kilometer downwind of the turbines. The three hour SO₂ air quality standard is 1300 $\mu\text{g}/\text{m}^3$, not to be exceeded more than once per year. Although the NO₂ emissions do not appear to be a direct threat to the annual average NO₂ standard, the Congress has directed EPA to establish a short term NO₂ standard. Unless this new standard has a numerical value significantly greater than 1000 $\mu\text{g}/\text{m}^3$ (and it probably won't), short-term ground level impact of NO₂ emissions from these stationary gas turbines may also reach levels near the new NO₂ ambient air quality standard.

BACT

Currently the best available control technology for this size and type of stationary gas turbine is:

- 1) Steam or water injection into the primary combustion zone of the gas turbine combustion cannisters at the rate of approximately 0.4-1.2 lbs water per lb of fuel to reduce peak combustion flame temperatures thus reducing thermally formed NO_x emission. Reduction of up to 80% can be achieved.

J. P. Subramani
PAGE EIGHT
June 14, 1978

2) The use of lower sulfur distillate fuel oil to reduce SO₂ emission. Residual oil could be used, but generally is not. It requires heating, special handling, and is usually high in sulfur content. Natural gas can be and is used, along with other very low sulfur fuels, such as kerosene and methanol, but they are not generally available in the quantities needed, at this time.

3) The use of improved combustion cannisters, that provide additional oxygen and turbulence in the primary combustion zone of the cannisters without excessively reducing the local combustion temperature, to minimize the formation and emission of smoke, HC, and CO particularly at low load conditions.

There are a variety of other technologies that could be used. But they have various characteristics which discourage their use at the present time.

For controlling any of these emissions, tail end clean-up such as lime or soda scrubbing for SO₂ removal or ammonia scrubbing for NO₂ removal are prohibitively expensive: two to three times the cost of the gas turbine.

There is a group of turbine combustion design changes, usually called 'dry controls' which on prototype gas turbines have resulted in NO₂ reduction as great as that achieved with water injection. But these techniques have not been fully demonstrated in commercial operation. Such techniques include catalytic combustion, pre-mixing and vaporizing air and fuel, improved fuel injection (atomization), variable combustion chamber geometry to improve turbulence, smooth out combustion chamber temperature profiles, and reduce residence time in the primary combustion zone (50% of the NO_x is formed within the first 0.5 milliseconds of combustion time; 100% within 3 milliseconds), exhaust gas recirculation (however the exhaust must be cooled to prevent engine malfunction), and off-stoichiometric combustion. Many of these techniques look promising and some combination of them will probably become the best technology, at least for smaller gas turbines, within the next 3-5 year.

RECOMMENDED EMISSION STANDARDS

In applying this technology the degree of emission reduction recommended is not as much a matter of what is technically feasible as it is a matter of what is economically reasonable within the constraint of what is needed to meet the applicable ambient air quality standards.

By using more water, NO₂ emissions can be reduced to very low levels, but at water to fuel ratios above about 1.4 the water injection begins to significantly interfere with efficient turbine operation. Cleaner fuels than #2 distillate fuel oil can be used but they are more costly and generally less available than #2

oil. # 2 distillate oil has an upper sulfur content limit of 0.7% however 0.3 - 0.5% s oil is generally available, and 0.1% sulfur distillate oil can be purchased, but at a higher cost.

Considering these factors, EPA has proposed the following as NSPS for stationary gas turbines:

The numerical emission limit for NO_x is to be 75 ppm by volume corrected to 15 percent oxygen and ISO ambient atmosphere conditions. The proposed standard would also include an adjustment factor for gas turbine efficiency and a fuel-bound nitrogen allowance. NO_x emissions from gas turbines, therefore, would be limited according to the following equation:

$$STD = (0.0075 E) + F$$

where:

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen)

E = efficiency adjustment factor:

$$\frac{14.4 \text{ kilojoules/watt} \cdot \text{hr}}{\text{Actual ISO heat rate}}$$

F = fuel-bound nitrogen allowance:

<u>Fuel-Bound Nitrogen</u> (percent by weight)	F (NO _x - percent by volume)
N ≤ 0.015	$\frac{0.01}{0.01}$
0.015 < N ≤ 0.1	0.04 (N)
0.1 < N ≤ 0.25	0.004 + 0.0067 (N-0.1)
N > 0.25	0.005

During performance tests to determine compliance with the proposed standard, measured NO_x emissions at 15 percent oxygen would be adjusted to ISO ambient atmospheric conditions by the following correction factor:

$$NO_x = (NO_{x_{obs}}) \left(\frac{P_{ref}}{P_{obs}} \right)^{0.5} e^{19(H_{obs} - 0.00633)}$$

Where:

NO_x = emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.

NO_{x_{obs}} = Measured NO_x emissions at 15 percent oxygen, ppmv.

P_{ref} = Reference combustor inlet absolute pressure at

101.3 kilopascals (1 atmosphere) ambient pressure.

P_{obs} = Measured combustor inlet absolute pressure.

H_{obs} = Specific humidity of ambient air.

e = Transcendental constant (2.718)

The numerical emission limit for SO_2 would be 150 ppm by volume corrected to 15 percent oxygen or a fuel sulfur content limit of 0.8 percent by weight. There would be no efficiency adjustment factor or ambient condition correction factor for SO_2 emissions, since SO_2 emissions are not affected by gas turbine efficiency or ambient atmospheric conditions.

Higher efficiencies are normally achieved by increasing combustor operating pressures and temperatures and NO_x formation generally increases exponentially with increased pressure and temperature. High efficiency turbines, therefore, generally discharge gases with higher NO_x concentrations than low efficiency turbines. A concentration standard based on low efficiency turbines could restrict the use of some high efficiency turbines. Conversely, a concentration standard based on high efficiency turbines could allow such high NO_x concentrations that low efficiency turbines would require no controls. Consequently, having selected a concentration format for standards of performance, an efficiency adjustment factor needs to be selected to permit higher NO_x emissions from high efficiency gas turbines.

As mentioned above, NO_x emissions tend to increase exponentially with increased efficiency. It is not reasonable from an emission control viewpoint, however, 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 an efficiency adjustment factor should be to give an emissions credit for the lower fuel consumption of high efficiency gas turbines. Since the relative fuel consumption of gas turbines varies linearly with efficiency, a linear efficiency adjustment factor is selected to permit increased NO_x emissions from high efficiency gas turbines. A linear efficiency adjustment factor also effectively limits NO_x emissions to a constant mass emission rate per unit of power output.

The efficiency adjustment factor needs to be referenced to a baseline efficiency. Since most existing simple cycle gas turbines fall in the range of 20 to 30 percent efficiency, 25 percent is selected as the baseline efficiency. The efficiency of stationary gas turbines is usually expressed in terms of heat rate which is the ratio of heat input, based on lower heating value (LHV) of the fuel, to the mechanical power output. The heat rate of a gas turbine operating at 25 percent efficiency is 14.4 kilojoules per watt-hr (10,180 Btu per hp-hr). Thus, the following linear adjustment factor is selected to permit increased NO_x emissions from high efficiency stationary gas turbines:

$$x_a = x \cdot \frac{14.4}{Y} \quad x \cdot \frac{14.4}{Y}$$

where:

- x_a = adjusted NO_x emissions permitted at 15 percent oxygen and ISO conditions, ppmv.
- x = NO_x emission limit specified in the standards at 15 percent oxygen and ISO conditions, (i.e. 75 ppmv).
- Y = LHV heat input per unit of power output (kilojoules/watt-hr).

NOTE: ISO conditions refers to standard atmospheric conditions of 760 mm mercury, 288° Kelvin and 60 percent relative humidity.

The only intent of this efficiency adjustment factor is to permit a linear increase in NO_x emissions with increased efficiencies above 25 percent. Consequently, the adjustment factor would not be used to adjust the emission limit downward for gas turbines with efficiencies of less than 25 percent.

In the event of future limited distillate oil supplies, many new gas turbines would probably be designed to fire residual or heavy fuel oils. Consequently, in order to provide gas turbine owners and operators the flexibility to fire either premium or heavy and residual fuel oils, but to ensure that standards of performance add no impetus toward the firing of heavy fuel oils as a means of evading standards, a fuel bound nitrogen allowance is proposed for the standard of performance limiting NO_x emissions from stationary gas turbines.

An allowance in the NO_x emission limit dependent on fuel-bound nitrogen level with no upper limit on emissions, however, could permit extremely high NO_x emissions when firing some very high nitrogen-containing fuels. Thus, it is essential that restraints be placed on such an emission allowance. A fuel-bound nitrogen allowance has been developed that allows

approximately 50 percent use of the heavy fuel oils such as #6 fuel oil (desulfurized). This corresponds to a fuel-bound nitrogen content of about 0.25 weight percent. Firing a fuel with 0.25 weight percent fuel-bound nitrogen increases controlled NO_x emissions by about 50 ppm. Consequently, a fuel-bound nitrogen NO_x emission allowance based on a straight line approximation of the relationship between total NO_x emissions and fuel-bound nitrogen content with a maximum allowance of 50 ppm, due to fuel bound nitrogen is selected for the standard of performance.

The effect of ambient atmospheric conditions on NO_x emissions from stationary gas turbines is substantial. Large changes in relative humidity, for example, can cause NO_x emissions to vary by a factor of 2 or more. In order to insure that standards of performance are enforced uniformly, therefore, the effect of ambient atmospheric conditions on NO_x emission levels needs to be taken into account. The equation presented above to correct measured NO_x emissions to ISO ambient atmospheric conditions was derived by extracting the common elements from several ambient correction factors proposed by gas turbine manufacturers. This correction factor, therefore, represents the general effect of ambient atmospheric conditions on NO_x emissions. Consequently, the correction factor listed above, or an alternative factor as discussed below, is to be used to adjust measured NO_x emissions during any performance test to determine compliance with the numerical emission limit.

As an alternative, gas turbine manufacturers may elect to develop custom correction factors for adjusting measured NO_x emissions from particular gas turbine models. Some gas turbine manufacturers have proposed ambient correction factors which include variables such as fuel-to-air ratios and combustor temperatures. These variables are difficult to measure and are operating parameters which may vary widely due to factors other than atmospheric conditions.

Correction factors to adjust NO_x emissions to a reference humidity and pressure are recommended. If a manufacturer develops a correction factor for humidity and pressure specifically for his model of turbine, he may use those correction factors after submittal of substantiating data to EPA and approval by EPA. Correction factors for temperature are optional and, if used, must be developed by the manufacturer for the specific model. The International Standards Organization (ISO) standard day conditions of one atmosphere, 59°F and 60 percent relative humidity are chosen as the reference conditions. Since the existing correction factors were developed by manufacturers for turbines which use conventional combustors operating at, or near, stoichiometric conditions, they cannot be applied to turbines which use emerging technology combustors such as the

J. P. Subramani
PAGE THIRTEEN
June 14, 1978

low emission lean-burn types which operate at off-stoichiometric conditions. Correction factors for turbines which use non-conventional combustors must be developed by the manufacturer and approved by EPA for each specific turbine model.

For large gas turbines used to generate peaking power and burning distillate fuel oil, such as the FPC proposed turbines, the rate of efficiency decrease can be expected to be about 1 percent per year, due to degradation of the combustors, and erosion and/or deposits on the compressor or turbine blades. Deposits are usually removed by steam cleaning or by introducing crushed walnut shells or rice hulls into the air intake. Combustor life can be estimated so that maintenance activities and compliance tests can be scheduled accordingly. Decrease in efficiency can be monitored by standard process instrumentation, by measuring such things as pressure ratios, exhaust temperatures, and fuel flow. Turbines equipped with water injection should have equipment to continuously measure the water/fuel ratio. Compliance test should be conducted after each major turbine repair and when combustor sections are modified or replaced using EPA Test Method 20-Determination of NO_x, SO₂, and O₂ emissions from Stationary Gas Turbines, a copy of which is attached. Tests should be conducted at full load conditions, using the highest sulfur content fuel normally used, with the turbine operated at the A/F ratio normally used, with the water injection/fuel ratio typically used.

The reason for selecting a concentration standard is the fact that the high turbulence of turbine exhaust gas makes the determination of exhaust flow rates subject to considerable error. Concentration measurements will generally be more accurate and less expensive. To prevent circumvention of the standard by adding dilution air the concentration standard is tied to a specified oxygen content in the exhaust gas: 15% by volume which approximately corresponds to the normal amount of excess air used to properly operate such turbines.

Since SO₂ emissions are directly related to the amount of sulfur in the fuel, SO₂ emissions can be determined from a fuel quality analysis and measurements of fuel use.

Opacity can be determined by a trained observer using standard observation procedures based on a six minute average opacity - one observation each 15 seconds.

J. P. Subramani
PAGE FOURTEEN
June 14, 1978

If we were to consider large stationary gas turbines as a class, I would recommend the adoption of the US EPA proposed NSPS with the addition of an opacity standard and a tighter SO₂ standard, in the range of 100-125 ppmv.

Considering the four (4) large turbines proposed by FPC as individual units, I recommend that NO₂ emission be limited to no more than 75 ppmv adjusted and corrected as in the EPA proposal; SO₂ be limited to no more than 100 ppmv; with an opacity standard of no more than 20%. I think that in this particular case it might be reasonable to require a tighter set of standards such as 60 ppmv NO₂, 80 ppmv SO₂, and 10% opacity. Such a set of standards are achievable, particularly if FPC intends to use and has a long term supply of high quality distillate oil (#1 oil), but their BACT application does not provide information on which to base an economic analysis of this alternative vs. their proposal of 75 ppmv NO₂, 95 ppmv SO₂, and 20% opacity.

Before making a final determination on BACT for these specific turbines, you may wish to consider some of the points raised in the next section.

COMMENTS

1. On the BACT application forms, FPC listed each turbine as generating 63,000 MW at peak load. This is a typographical error. They apparently meant 63 MW. In an attachment to the application, each unit was listed as 63,000 KW peak load, with the whole installation rated at 200 MW base load. This agrees with the AP-42 assumption of peak load being 1.25 times base load. One of the largest coal-fired steam-electric units in the country generates only 1300 MW. (the whole plant, which consists of three units, generates 2900 MW.)
2. FPC lists the specification for the distillate oil they plan to burn as 6.8 #/gal, 19,494 BTU/lb, with a maximum sulfur content of 0.5%. These are approximately the specifications for #1 distillate oil. #2 oil specifications are: 7.3 #/gal, 19,420 BTU/lb, with a maximum sulfur content of 0.7%. Both #1 and #2 oil are to have a water and sediment content of less than 0.1%. These standard specifications are based on the National Oil Fuel Institute's publication No. 68-101 "Fuel Oil Specifications".

3. In some cases steam injection appears to be more effective in reducing NO_x . In other cases water injection seems to work best. The difference appears to be related to specific design of the various machines tested and the way in which the injection is accomplished. Either steam or water injection are acceptable control techniques for NO_x .
4. Gas turbines are less fuel efficient than reciprocating engines, but they generally release lesser amounts of air pollutants. Diesel engines of comparable size to the turbines proposed by FPC, to my knowledge, do not exist.
5. Per pound of gas or oil burned, gas turbines, generally emit more HC, CO, and NO_x than external combustion boilers.
6. Feed water for the water injection system should be filtered and demineralized (less than 1% sodium) but it does not need to be of boiler feedwater purity.
7. In an attachment to their application (Exhibit B) FPC indicated that at a 1 to 1 water to fuel ratio turbine efficiency would be reduced by 6.95%. This was based on assuming that all of the heat used to vaporize the water and raise this vapor to 726°F (the stack gas exit temperature) was lost. Therefore, the 700 BTU's per lb for vaporation plus the 656 BTU/lb to raise the vapor temperature to 726°F was lost. Hence $(1356/19,500)$ 6.95% of the heat input value of the fuel would be unavailable for producing work output.

The overall efficiency of a heat engine is a function of the total heat input and the usable heat or work output. The heat rejected to the stack is lost whether it is transported by dry stack gas or by water vapor. In the engine, the water vapor absorbs and transfers usable energy. The real loss due to water injection is the unrecoverable heat used to convert liquid water to vapor, approximately 700 BTU/lb, about a 3.6% decrease in available heat input energy. If the turbine was 30% efficient without water injection, each BTU heat input would produce 0.30 BTU of work or electric energy output. A 3.6 decrease in available input energy would decrease output energy by the same amount. Thus the output would drop to 0.289 BTU's output, or an overall 1 percent decrease in thermal efficiency. The primary reason for low efficiency for gas turbines is the large amount of heat rejected to the stack. However, even if the turbine was a perfect thermal machine operating at a temperature of 3000°F (3460°R), with an ambient air temperature of 70°F (530°R) the highest thermal efficiency possible, due to thermodynamic considerations, would be $85\% (3460-530)/3460$. If such a machine rejected heat at 726°F (1186°R) its maximum possible efficiency would be 65%.

8. Table 4.2 on page 4-28 of EPA's SSEIS document for stationary gas turbines list 58 turbine installations which are currently on order or in operation with either water or steam injection. Seven installations were listed for Florida: One GE unit on order for the City of Jacksonville. One Westinghouse unit with 857 hours of operation owned by Jacksonville Electric; Four Westinghouse units owned by Florida Power and Light with water injection systems available, but not being used; one Westinghouse unit owned by Florida Power Company, located at Enterprise, Florida, with 718 hours of operation. Enterprise is in Volusia County, near Sanford.
9. The following is an analysis of the relationships among the data provided by FPC for each gas turbine.

Each turbine is to burn a maximum of 37,910 #/hr of light distillate fuel oil. Theoretical Air calculations indicate that about 14.5 lbs of air per lb of fuel is required for stoichiometric combustion. This results in 589,121 lbs/hr of exhaust or approximately 133,406 scfm of exhaust. Atmospheric moisture at 80°F would add about 2600 scfm. If a 1:1 water-fuel ratio is used for water injection the water would add about 14,000 scfm. At 15% oxygen there would be approximately 270% excess air, for a total dry volume of 470,420 scfm. FPC lists the exit gas volume for each turbine as 1,255,500 ACFM @ 726°F. It was not specified whether this was wet or dry volume. This would be a standard volume (at 60°F, 1atm) of 550,472 scfm. Assuming that this is meant to be wet or total volume including moisture, the turbine would be operated at 320% excess air which would correspond to 15.75% oxygen in the exit gas. Neither excess air or percent oxygen was specified in the application. Note the considerable change in indicated excess air for a small change in percent oxygen. This underscores the need for accurate O₂ measurements when conducting compliance tests.

Basing the 75 ppmv NO₂ standard on dry gas volume (Test Method 20 attached), and using the previously calculated dry volume of 470,420 scfm, the standard for these turbines is equivalent to 248 lb/hr emission, which agrees with FPC's estimate of 250 #/hr.

Using the same volume estimates, and FPC's recommended standard of 95 ppmv SO₂, I estimate an emission rate of 437 lb/hr, which corresponds to 0.575% S Fuel oil. FPC listed their maximum sulfur content at 0.5% S which is approximately equivalent to 80 ppmv. However, note that a small change in either exit volume due to a small change in theoretical air required, or sulfur content, or fuel heating value could result in 0.5 sulfur fuel being equivalent to 90-100 ppmv. Burning 0.5% sulfur light fuel

oil results in SO₂ emissions of approximately 0.51 lbs/MMBTU. EPA's SSEIS document on gas turbines says that 150 ppmv is approximately equivalent to 0.8% S in fuel oil, which would imply that 95 ppmv is roughly equivalent to 0.5% sulfur.

10. There are several questions which I have noted in this report which you may wish to obtain more information on, before declaring BACT for these turbines, or before a Construction Permit is issued, whichever is appropriate.

Is an economic analysis of an alternate set of standards, such as 60 ppmv NO₂, 80 ppmv SO₂ and 10% opacity appropriate or necessary? If so additional information is needed.

What amount of "spinning reserve" is planned for these turbines?

What is the possibility of all four turbines operating at full load at the same time? It might affect the PSD review.

What other SO₂ sources are located near this site? An attachment to the BACT application indicated that there are existing fossil-fuel fired units at this site.

What bearing does EPA's development of a short term NO₂ standard have on the permit review for this facility? ²

What is the Air/fuel ratio for maximum load operation? What is the excess air? Is the exit volume listed on a total or dry basis? What is the planned water to fuel ratio? What has been FPC's experience with water injection at their Enterprise plant? What is the possibility of increasing the stack height to, say, 45 feet? What is the source of their fuel oil supply, and how certain is FPC that they can continue to obtain high grade light fuel oil for gas turbine fuel?

Many of these questions do not necessarily need to be answered prior to making the BACT determination, but they probably should be answered before a construction permit is issued.

11. If the nominal 75 ppmv NO_x emission standard is applied, the FPC turbines would actually be allowed an emission rate of 87 ppmv due to the efficiency adjustment factor, which would increase all of the NO₂ emission estimates included in FPC BACT application and this report by 16.4% (29.1/25.0). 25% is the base efficiency for the adjustment factor. Typical gas turbine thermal efficiencies range from 20-30%.

SS/ca

Attachments
Turbine pictorial
EPA Test Method 20

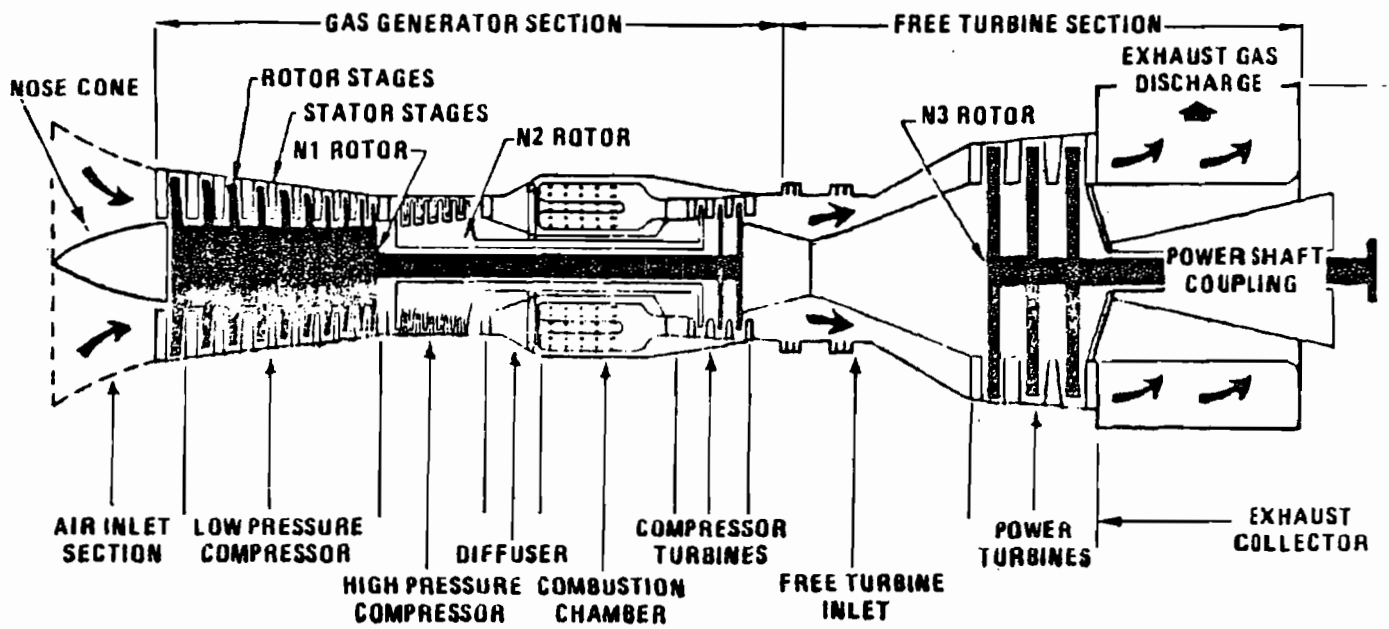


Figure 3-6. Cut away view of a typical simple cycle gas turbine.

APPENDIX - G

METHOD 20--DETERMINATION OF NITROGEN OXIDES, SULFUR DIOXIDE, AND OXYGEN EMISSIONS FROM STATIONARY GAS TURBINES

1. Principle and Applicability

1.1 Principle. A gas sample is continuously extracted from the exhaust stream of a stationary gas turbine; a portion of the sample stream is conveyed to instrumental analyzers for determination of nitrogen oxides (NO_x) and oxygen (O_2) content. During each NO_x and O_2 determination, a separate measurement of sulfur dioxide (SO_2) emissions is made, using Method 6, or its equivalent. The O_2 determination is used to adjust the NO_x and SO_2 to a reference condition.

1.2 Applicability. This method is applicable for the determination of nitrogen oxide, sulfur dioxide, and oxygen emissions from stationary gas turbines. For the NO_x and O_2 determinations, this method includes: (1) measurement system design criteria, (2) analyzer performance specifications and performance test procedures; and (3) procedures for emission testing.

2. Apparatus and Reagents

2.1 Measurement System. The equipment required to extract, transport, and analyze the gas sample constitutes the "measurement system." A schematic of the measurement system is shown in Figure 20-1. (Measurement system performance specifications are described in detail in Section 3.) The essential components of the measurement system are described below.

2.1.1 Probe. Stainless steel type 316 or equivalent, to transport gas from stack.

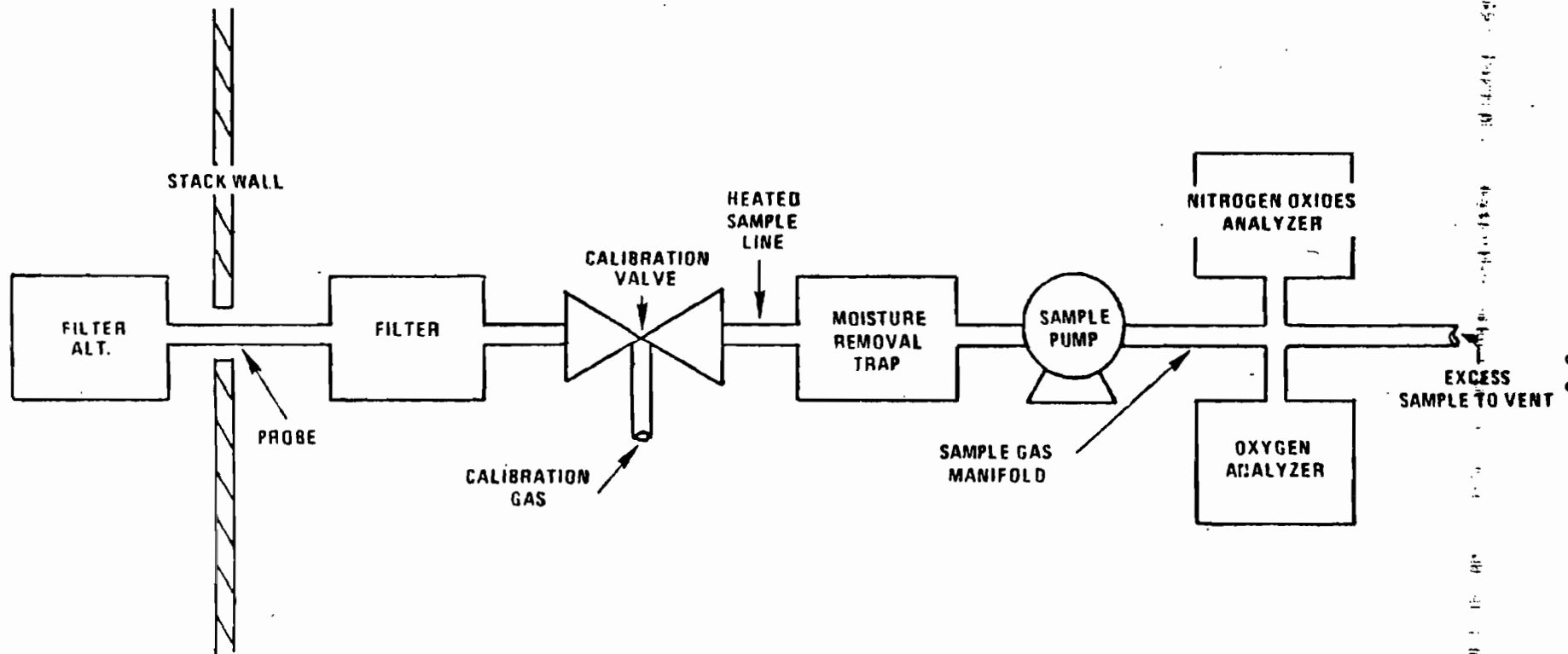


Figure 20.1 Measurement system design for stationary gas turbine tests.

2.1.2 Particulate Filter. A filter is used to remove particulates ahead of the calibration valve assembly. In most cases, either in-stack or out-stack filter location is acceptable; however, out-stack filtration is required when the sample gas temperature is above 500°C (930°F). The filtration temperature shall be at least 120°C (250°F) to prevent moisture condensation. Glass fiber filters, of the type specified in EPA Method 5, or equivalent, are recommended.

2.1.3 Calibration Valve Assembly. A three-way valve assembly is used to direct the zero and span calibration gases to the analyzers. This assembly shall be located directly behind the probe and filter and shall be capable of blocking the sample gas flow and introducing the span and zero gases when the system is in the calibration mode.

2.1.4 Calibration Gases. Calibration gases are used to perform zero, span and calibration checks of the analyzers during each test run. The concentrations and specifications of these gases are described in detail in Sections 2.2 and 6.2.

2.1.5 Heated Sample Line. A FEP fluorocarbon or stainless steel (type 316 or equivalent) sample line is used to transport the gases to the sample conditioner and analyzers. The sample gas shall be maintained at least 5°C (10°F) above the stack gas dew point to prevent moisture condensation.

2.1.6 Moisture Trap. A moisture trap, designed to reduce the dew point of the sample gas to 3°C (37°F) or less, is used. For instruments not affected by water vapor, this device is not required; however, the moisture content shall be determined using methods subject to the approval of the Administrator and the NO_x and O_2 concentrations shall be corrected to a dry gas basis.

2.1.7 Pump. A nonreactive leak-free sample pump is used to pull the sample gas through the system at a flow rate sufficient to minimize transport delay. The pump shall be made from or coated with nonreactive material (FEP fluorocarbon or type 316 stainless steel).

2.1.8 Sample Gas Manifold. A sample gas manifold is recommended for diverting portions of the sample gas stream to the analyzers. The manifold may be constructed of glass, FEP fluorocarbon, or stainless steel (type 316 or equivalent). Instead of using the manifold, separate sample lines may be connected to each analyzer.

2.1.9 Oxygen Analyzer. An oxygen analyzer is used to determine the oxygen concentration (percent O_2) of the sample gas stream.

2.1.10 Nitrogen Oxides Analyzer. A NO_x analyzer is used to determine the ppm concentration of nitrogen oxides in the sample gas stream.

2.1.11 Sulfur Dioxide Analysis. Method 6 apparatus, or equivalent, is required for sulfur dioxide determination.

2.2 Calibration Gas Specifications.

2.2.1 Zero Gas. Prepurified nitrogen is used.

2.2.2 Nitrogen Oxide Calibration Gases. Mixtures of known concentrations of NO in nitrogen are required. Nominal NO concentrations of 25, 50, and 90 percent of the instrument full scale range are needed. The 90 percent gas mixture is used to set and check the instrument span and is referred to as span gas. The 25 and 50 percent gas mixtures shall be used to validate the analyzer calibration, prior to each test.

2.2.3 Oxygen Calibration Gases. Ambient air at 20.9 percent oxygen shall be used as the span gas (high range concentration gas). A midscale calibration gas (approximately 13 percent O_2 in nitrogen) shall be used to validate the analyzer calibration prior to each test.

2.2.4 Concentration Validation. Within one month prior to test use, calibration gases shall be analyzed, by the appropriate test method specified in Section 6.2, to determine their true concentration levels. Gas concentrations that are traceable to the National Bureau of Standards and which can be demonstrated to be stable are exempted from the analysis requirements.

3. Measurement System Performance Specifications and Performance Test Procedures

3.1 Analyzer. "Span" is defined as the concentration range (specified by manufacturer) over which an analyzer will give valid readings. The spans for the analyzers used in this method shall be as follows:

3.1.1 Oxygen Analyzer: 0 to 25% O_2

3.1.2 NO_x Analyzer: 0 to 120 ppm

3.2 Analyzer Interferences and Interference Response. The "interference response" of an analyzer is defined as the output response to a component in the sample gas stream, other than the gas component being analyzed; the analyzers used in this method shall not have a total interference response of more than +2 percent of span.

Particulate matter and water vapor are the primary interfering species for most instrumental analyzers, but these may be removed physically by using filters and condensers. Other possible specific interferences found in turbine exhaust streams include carbon monoxide, carbon dioxide, nitrogen oxides, sulfur dioxide and hydrocarbons. Each analyzing instrument may respond to one or more of these interferences in ways that alter the desired measurement.

The interference response of an analyzer is determined by measuring the total analyzer response to the gaseous components (or mixtures) listed in Table 20.1; these gases may either be introduced into the analyzer separately, or as a single gas mixture. The total interference output response of the analyzer to these components, if any, shall be determined (in concentration units). The values obtained in an interference response test shall be recorded on a form similar to Figure 20.2. If the sum of the interference responses of the test gases is greater than 2 percent of the instrument span, the analyzer shall not be used in the measurement system of this method.

An interference response test of each analyzer shall be conducted prior to its initial use in the field. Thereafter, if changes are made in the instrumentation which could alter the interference response, e.g., changes in the type of gas detector, the instruments shall be retested.

In lieu of conducting the interference response test, instrument vendor data, which demonstrate that for the test gases of Table 20.1 the interference performance specification is not exceeded, are acceptable. If these data are not available, the tests shall be made.

TABLE 20.1 INTERFERENCE TEST GAS CONCENTRATIONS

CO	500 ppm
SO ₂	200 ppm
NO/NO ₂	200 ppm
CO ₂	10%
O ₂	20.9% (Air)

FIGURE 20.2 INTERFERENCE RESPONSE

Date of Test: _____

Analyzer Type: _____ S/N _____

<u>Test Gas Type</u>	<u>Conc.</u>	<u>Analyzer Output Response</u>	<u>% of Span</u>
_____	_____	_____	_____
_____	_____	_____	_____
_____	_____	_____	_____
_____	_____	_____	_____

$$\% \text{ of Span} = \frac{\text{Analyzer Output Response}}{\text{Instrument Span}} \times 100$$

3.3 Analyzer Response Time. When a change in pollutant concentration occurs at the inlet of the measurement system (i.e., at probe), the change is not immediately registered by the analyzer; "response time" is defined as the amount of time that it takes for the analyzer to register a concentration value within 5 percent of the new inlet concentration. The maximum response time for the analyzers used in this method is three minutes.

To determine response time, first introduce zero gas into the system until all readings are stable; then, introduce span gas into the system. The amount of time that it takes for the analyzer to register 95 percent of the final span gas concentration is the upscale response time. Next, reintroduce zero gas into the system; the length of time that it takes for the analyzer output to come within 5 percent of the final reading is the downscale response time. The upscale and downscale response times shall each be measured three times. The readings shall be averaged, and the average upscale or downscale response time, whichever is greater, shall be reported as the "response time" for the analyzer. Response time data are recorded on a form similar to Figure 20.3. A response time test shall be conducted prior to the initial field use of the measurement system, and shall be repeated if changes are made in the measurement system.

3.4 Zero Drift. "Zero drift" is the change in analyzer output during a turbine performance test, when the input to the measurement system is a pure grade of nitrogen (zero gas). The maximum allowable

RESPONSE TIME

Date of Test _____	
Analyzer Type _____	S/H _____
Span Gas Concentration _____ ppm	
Analyzer Span Setting _____ ppm	
Upscale	1 _____ seconds
	2 _____ seconds
	3 _____ seconds
Average upscale response _____ seconds	
Downscale	1 _____ seconds
	2 _____ seconds
	3 _____ seconds
Average downscale response _____ seconds	
System response time = slower average time = _____ seconds.	

Figure 20.3

zero drift for the analyzers used in this method is ± 2 percent of the specified instrument span. The zero drift calculation is made for each gas for each turbine test run; this is done by taking the difference of the zero gas concentration values measured at the start and finish of the test (see Section 6.1). The zero drift is recorded (as a percentage of the instrument span) on a form similar to Figure 20.4.

3.5 Span Drift. "Span drift" is the change in the analyzer output during a turbine performance test, when the input to the measurement system is span gas. The maximum allowable span drift for the analyzers used in this method is ± 2 percent of the specified instrument span. The span drift calculation is to be made for each gas for each turbine test run; this is done by taking the difference between the span gas concentration values measured at the beginning and end of the test. Span drift is recorded (as a percentage of instrument span) on a form similar to Figure 20.4. Span drift must be corrected for any zero drift that occurred during the test period (see Figure 20.4).

4. Procedure for Field Sampling

4.1 Selection of a Sampling Site and the Minimum Number of Traverse Points.

4.1.1 Select a sampling site as close as practical to the exhaust of the turbine. Turbine geometry, stack configuration, internal baffling, and point of introduction of dilution air will vary for different turbine designs. Thus, each of these factors must be given special consideration in order to obtain a representative sample. Whenever possible, the sampling site shall be located upstream of the

TURBINE SAMPLING SYSTEM

Zero and Span Drift Data

Turbine: Type _____ S/N _____

Date: _____

Test No.: _____

Analyzer: Type _____ S/N _____

	Initial Calibration ppm or %	Final Calibration ppm or %	Difference Initial-Final ppm or %	% of Span
Zero Gas				
High Calibration Gas (Span Gas)			*	

$$\% \text{ of Span} = \frac{\text{Absolute Value of Difference}}{\text{Instrument Span}} \times 100$$

*Corrected for zero drift, i.e., if zero drift over test period is +2 ppm then 2 ppm shall be subtracted from the difference between the initial and final readings.

Figure 20.4

point of introduction of dilution air into the duct. Sample ports may be located before or after the upturn elbow, in order to accommodate the configuration of the turning vanes and baffles and to permit a complete, unobstructed traverse of the stack. The sample ports shall not be located within 5 feet or 2 diameters (whichever is less) of the gas discharge to atmosphere. For supplementary-fired, combined-cycle plants, the sampling site shall be located between the gas turbine and the boiler.

4.1.2 The minimum diameter of the sample ports shall be 3-inch nominal pipe size (NPS).

4.1.3 The minimum number of points for the preliminary O_2 sampling (Section 8.3.2) shall be as follows: (1) eight, for stacks having cross-sectional areas less than 1.5 m^2 (16.1 ft^2); (2) one sample point for each 0.2 m^2 (2.2 ft^2) of area, for stacks of 1.5 m^2 to 10.0 m^2 ($16.1 - 107.6 \text{ ft}^2$) in cross-sectional area; and (3) one sample point for each 0.4 m^2 (4.4 ft^2) of area, for stacks greater than 10.0 m^2 (107.6 ft^2) in cross-sectional area. Note that for circular ducts, the number of sample points must be a multiple of 4, and for rectangular ducts, the number of points must be one of those listed in Table 20.2; therefore, round off the number of points (upward), when appropriate.

4.2 Cross-sectional Layout and Location of Traverse Points. After the number of traverse points for the preliminary O_2 sampling has been determined, use Method 1 to locate the traverse points.

TABLE 20.2 CROSS-SECTIONAL LAYOUT FOR RECTANGULAR STACKS

<u>No. of traverse points</u>	<u>Matrix layout</u>
9	3 x 3
12	4 x 3
16	4 x 4
20	5 x 4
25	5 x 5
30	6 x 5
36	6 x 6
42	7 x 6
49	7 x 7

4.3 Measurement System Operation.

4.3.1 Preliminaries.

4.3.1.1 Prior to the turbine test, the measurement system shall have been demonstrated to have met the performance specifications for interference response and response time described in Sections 3.2 and 3.3.

4.3.1.2 Turn on the sample pump and instruments; allow the normal warmup time required for stable instrument operation.

4.3.1.3 After the instruments have stabilized, the measurement system shall be calibrated using the procedures detailed in Section 6.1. Transfer the zero and span gas calibration data from Figure 20.5 to a form similar to Figure 20.4.

4.3.1.4 At the beginning of each NO_x test run and, as applicable, during the run, record turbine data as indicated in Figure 20.6. Also, record the location and number of the traverse points on a diagram.

4.3.2 Preliminary Oxygen Sampling.

4.3.2.1 At the start of a 3-run sample sequence, position the probe at the first traverse point and begin sampling. The minimum sampling time at each point shall be 1 minute plus the average system response time. Determine the average steady-state concentration of O_2 at each point and record the data on Figure 20.7.

4.3.2.2 Select the eight sample points at which the lowest oxygen concentrations were obtained. These same points shall be used for all three runs which comprise the emission test. More points may be used, if desired.

Figure 20.5
CALIBRATION DATA

Date _____	
Analyzer Type _____	S/II _____
High Range Gas Conc. _____	% Full Scale _____
Mid Range Gas Conc. _____	% Full Scale _____
Low Range Gas Conc. _____	% Full Scale _____
Zero Gas _____	% Full Scale _____

Figure 20.6
STATIONARY GAS TURBINE

TURBINE OPERATION RECORD			
Test Operator _____	Date _____		
Turbine ID	Type _____	Ultimate Fuel	
	S/N _____	Analysis C _____	
		H _____	
Location	Plant _____	O _____	
	City _____	N _____	
		S _____	
Ambient Temperature _____		Ash _____	
		H ₂ O _____	
Ambient Humidity _____	Trace Metals		
Test Time Start _____	_____		
	Na _____		
Test Time Finish _____	Va _____		
	K _____		
Fuel Flow Rate _____ *	etc. ** _____		
Water or Steam _____ *	Operating Load _____		
Flow Rate _____			
Ambient Pressure _____			
* Describe measurement method, i.e., continuous flow meter, start finish volumes, etc.			
** i.e., Additional elements added for smoke suppression.			

FIGURE 20.7

Preliminary Oxygen Traverse

Location _____		Date _____
Plant _____		
City, State _____		
Turbine ID _____		
Mfg. _____		
Model, serial number _____		
Sample Point	Oxygen Concentration	

4.3.3 Emission Sampling.

4.3.3.1 Position the probe at the first point determined in the preceding section and begin sampling. The minimum sampling time at each point shall be 3 minutes plus the average system response time. Determine the average steady-state concentration of O_2 and NO_x at each point and record the data on Figure 20.8.

4.3.2.2 After sampling the last point, conclude the test run by recording the final turbine operating parameters and by determining the zero and span drift, as described in Sections 3.4 and 3.5. If the zero and/or span drift exceed ± 2.0 percent the run may be considered invalid, or may be accepted provided the calibration data which results in the highest corrected emission concentration is used.

4.3.2.3 If additional turbine runs are conducted within 4 hours of the previous run, an initial calibration of the measurement system is not required. If more than 4 hours have elapsed between runs, the pretest calibration shall be done.

4.4 An SO_2 determination shall be made (using Method 6, or equivalent) during the test. A minimum of six total points, selected from those required for the NO_x measurement, shall be sampled; two points shall be used for each sample run. The sample time at each point shall be at least 10 minutes. The oxygen readings taken during the NO_x test runs corresponding to the SO_2 traverse points (see Section 4.3.3.1) shall be averaged, and this average oxygen concentration shall be used to correct the integrated SO_2 concentration obtained by Method 6 to 15 percent O_2 (see Equation 20-1).

Figure 20.8
STATIONARY GAS TURBINE
GAS SAMPLE POINT RECORD

Turbine ID Mfg. _____
 Model & S/N _____
 Plant _____
 Location City _____
 State _____
 Ambient Temp. _____
 Ambient Press _____
 Ambient Humidity _____
 Date _____
 Test Time Start _____
 Test Time Finish _____

Test Operator Name _____
 O₂ Instrument Type _____ S/N _____
 NO_x Instrument Type _____ S/N _____

G-19

Sample Point	Time (Min)	O ₂ [*] (%)	NO _x [*] (ppm)
1	0		

*Average steady state value from recorder or instrument readout.

5. Emission Calculations

5.1 Correction to 15 Percent Oxygen. Using Equation 20-1, calculate the NO_x and SO_2 concentrations (adjusted to 15 percent O_2). The correction to 15 percent oxygen is sensitive to the accuracy of the oxygen measurement. At the level of analyzer drift specified in the method (± 2 percent of full scale), the change in the oxygen concentration correction can exceed 10 percent when the oxygen content of the exhaust is above 16 percent O_2 . Therefore O_2 analyzer stability and careful calibration are necessary.

$$\text{Actual Pollutant Concentration (NO}_x \text{ or SO}_2\text{)} \times \frac{5.9\%}{20.9\% - \text{O}_2\% \text{ actual}} = \text{Pollutant concentration adjusted to 15\% O}_2$$

Equation 20-1

where:

5.9% is 20.9% - 15% (the defined concentration basis).

O_2 actual is the sample point oxygen concentration for NO_x calculation, and the average O_2 concentration for SO_2 calculation.

5.2 Calculate the average adjusted NO_x concentration by summing the point values and dividing by the number of sample points.

6. Calibration

6.1 Measurement System. Prior to each turbine test, the measurement system shall be calibrated according to the procedures described below. The manufacturer's operation and calibration instructions are also to be followed as required for each specific analyzer.

6.1.1 Turn on all measurement system components and allow them to warm up until stable conditions are achieved. Next, introduce zero gas and each of the calibration gases described in Section 6.2, one at a time, into the inlet of the probe. The responses of the analyzer to these gases shall be used to establish a calibration curve or to verify the manufacturer's calibration curve. The data obtained in these procedures shall be recorded on a form similar to Figure 20.4. If, for the mid-scale gases, the accuracy of the manufacturer's calibration curve or the expected response curve cannot be shown to be ± 2 percent of full scale (or better), the calibration shall be considered invalid and corrective measures on the instrument shall be taken. The calibration procedure shall be repeated, using only zero gas and span gas, at the conclusion of test; this allows calculation of zero and span drift (Sections 3.2 and 3.3).

6.2 Calibration Gas Mixtures.

6.2.1 Within one month prior to the turbine test, the NO_x calibration gas mixtures shall be analyzed, using the phenoldisulfonic acid procedure (Method 7) for nitrogen oxides. A minimum of three analyses shall be done, and the average concentration of each gas shall be reported as the true calibration gas value (see Figure 20.9). Alternate procedures may be employed, subject to the approval of the Administrator, to determine the calibration gas concentration.

Note: The NO_x calibration gas mixtures shall contain nitric oxide (NO) in nitrogen. Instruments which require conversion of one nitrogen

Figure 20.9

ANALYSIS OF CALIBRATION GAS MIXTURES

CALIBRATION GAS COMPOSITION	Reference Method Used _____
Date: _____	
<u>Low Range Calibration Gas Mixture</u>	
Sample 1 _____ ppm	
Sample 2 _____ ppm	
Sample 3 _____ ppm	
Average _____ ppm	
<u>Mid Range Calibration Gas Mixture</u>	
Sample 1 _____ ppm	
Sample 2 _____ ppm	
Sample 3 _____ ppm	
Average _____ ppm	
<u>High Range (span) Calibration Gas Mixture</u>	
Sample 1 _____ ppm	
Sample 2 _____ ppm	
Sample 3 _____ ppm	
Average _____ ppm	

oxide component to another for total NO_x measurement shall be checked to ensure that this conversion is complete and reproducible, as specified by the manufacturer.

6.2.2 Ambient air may be used as the oxygen span gas. The mid-scale calibration gas concentration shall be certified (by vendor) as being within ± 2 percent of the indicated concentration.

Walt Starnes

State of Florida

DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices
And/Or To Other Than The Addressee

To: _____	Loctn.: _____
To: _____	Loctn.: _____
To: _____	Loctn.: _____
From: _____	Date: _____

TO: J. P. Subramani

THROUGH: Frank Darabi ⁽⁷⁾

FROM: Ray DiNardo ^(RD)

DATE: June 13, 1978

SUBJECT: BACT Deterinimation for 4 stationary gas turbines to be constructed at the Suwannee River Power Plant site, Suwannee County Florida.

Florida Power Corporation proposes control strategy on each of 4 63 kw distillate oil fired gas turbines as follows:

Particulate - Design. SO_x - Limit % sulfur to .5% by wieght; concentrations not to exceed 95 ppm by volume. The EPA proposed SO_x turbine standard is 150 ppm by volume. NO_x - H₂O/Steam injection or combustion design not to exceed 75 ppmv. Opacity - < 20% by design.

DER Gainesville proposed standards: Particulate - Emissions are not to exceed .08 #/mm BTU. FPC is allowed 59.12 #/hr @ 739 X 10⁶ BTU/hr heat in. The proposed standard is a reduction of 20% from the EPA steam performance reg. It is expected that FPC will be able to comply utilizing low ash content fuel and advanced combustor design. SO_x - limit fuel oil to .3% by weight. FPC is allowed only 114 #/hr per turbine (assuming 37910 # of distillate in.) and would emit 85 tons per year. FPC esitmates SO_x emissions at 379 #/hr and 284 tons/yr. The proposed fuel sulfur limitation would provide for a substantial reduction in SO_x emissions at a location with a potential for high SO₂ concentrations. Fuel containing .3% S is currently available in Suwannee County. NO_x - A concentration of 75 ppmv is proposed. The standard is equivalent to the EPA proposed turbine standard and is achievable through H₂O, steam injection or an alternate technology with a removable efficiency in excess of 65%. Increased construction, maintenance, and operational costs in conjunction with overall efficiency loss discourages more stringent standards. OPACITY - a 20% standard is proposed. HC, CO - no standards proposed. NOISE should be minimized so as not to constitute annoyance at property lines. DISCUSSION: Emission control for gas turbines is currently achieved through low sulfur fuels, fuel additives, combustion modification,

continued....

and water or steam injection. Advanced NO_x control technology provides for staged fuel injection and combustion at various axial positions to maintain desired temperatures and or fuel/air ratio throughout the combustor. This method is preferable assuming adequate efficiency when consideration is given to economics, fuel consumption and maintenance costs. FPC declares dry NO_x control commercially unavailable at present; Mr. Donald Goodling, Westinghouse Gas Turbine Division, is in agreement. Teller Environmental Systems, Worcester Mass., markets innovative turbine control technology for particulates, NO_x, opacity, and noise. Control strategy incorporates flow augmentation, quenching, and a "nucleator" collector for low energy submicron particle collection. (APCA Journal February 1977 Vol. 27.2) test data; however, is not available to certify lower emissions for a 35 mw turbine unit.

There are fundamental design conflicts between CO and HC control on one hand and NO_x control on the other, especially when fuel economy, energy, and opacity are considered. Lowering the average temperature in the primary zone will greatly reduce NO_x, but will increase CO and HC. A cooling of the combustion process will result in nonoxidation of CO to CO₂. CO and HC are complex functions of air fuel ratio, degree of mixing and velocity. Smoke typically increases with combustor total inlet pressure and decreases with total temperature. Fuel additives can be effective in reducing opacity improving combustion; however, additives could have an adverse impact on engine life and may be a potential health hazard. There is a narrow band of temperatures and design specification within which it is possible to maintain acceptable emission levels. It is expected that suitable design and equipment standards in conjunction with wet NO_x control can be considered state of the art technology.

Although standards proposed by this office are reasonable, total hourly emissions would be in vilation of SDAPCD and LACAPCD regulations. Compliance with California standards could be achieved by decreasing the design output and increasing the number of peaking units with an overall reduction in total efficiency. An alternative would require expanded capacity of the primary generating facility.

Should you have any questions, please call.

RD/FD/bs

State of Florida

DEPARTMENT OF ENVIRONMENTAL REGULATION

INTEROFFICE MEMORANDUM

For Routing To District Offices And/Or To Other Than The Addressee	
To: _____	Loctn.: _____
To: _____	Loctn.: _____
To: _____	Loctn.: _____
From: _____	Date: _____

TO: J. P. Subramani

THROUGH: Frank Darabi ⁽⁷⁾

FROM: Ray DiNardo ^(RD)

DATE: June 13, 1978

SUBJECT: BACT Deterinimation for 4 stationary gas turbines to be constructed at the Suwannee River Power Plant site, Suwannee County Florida.

Florida Power Corporation proposes control strategy on each of 4 63 kw distillate oil fired gas turbines as follows:

Particulate - Design. SO_x - Limit % sulfur to .5% by wieght; concentrations not to exceed 95 ppm by volume. The EPA proposed SO_x turbine standard is 150 ppm by volume.
 No_x - H₂O/Steam injection or combustion design not to exceed 75 ppmv. Opacity - < 20% by design.

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Should you have any questions, please call.

RD/FD/bs

ATTACHMENT C
DER'S PROPOSED BACT