NORTHEAST STATES FOR COORDINATED AIR USE MANAGEMENT (NESCAUM)

MEMBERS:

CONNECTICUT BUREAU OF AIR MANAGEMENT
MAINE BUREAU OF AIR QUALITY CONTROL
MASSACHUSETTS DIVISION OF AIR QUALITY CONTROL
NEW HAMPSHIRE AIR RESOURCES DIVISION
NEW JERSEY OFFICE OF ENERGY
NEW YORK DIVISION OF AIR RESOURCES
RHODE ISLAND DIVISION OF AIR AND HAZARDOUS MATERIALS
VERMONT AIR POLLUTION CONTROL DIVISION

NESCAUM STATIONARY SOURCE COMMITTEE RECOMMENDATION ON EMISSION LIMITS FOR NEW COMBUSTION TURBINES

October 1991

This recommendation applies to simple or combined cycle combustion turbines, operating more than 2500 hr/yr. A recommendation on simple cycle turbines operating less than 2500 hours is available from NESCAUM. Limits different from these may be considered if an applicant proposes an advanced or innovative combustion technology. Consideration may also be given to high efficiency equipment.

Applicants are advised that the thresholds that trigger new source review for major sources and major modifications will be lowered according to an area's nonattainment classification. A new or modified source that is defined as a major source, or major modification, will be subject to new source review permitting requirements, probably including lowest achievable emission rates (LAER) and offsets for NO_x emissions.

<u>All emission limits in ppmv reflect dry basis, corrected to 15% oxygen</u>

I. Nitrogen Oxide Emission Limits

A. 1 MMBtu/hr to 100 MMBtu/hr (note 1)

Gas use	42 ppmv (note 2)
Oil use	65 ppmv (notes 2 and 7)

B. Greater than 100 MMBtu/hr (note 1)

Gas or oil as primary fuel	9 ppmv (notes 2 and 3)
Gas primary fuel with oil back-up fuel in use	
	9 ppmv for gas (notes 2 and 3)
	18 ppmv for oil (notes 2, 3 and 7)

II. Carbon Monoxide Emission Limits

Gas or Oil use	50 ppmv (note 2)

Lower CO limits will be considered on a case-by-case basis as part of the permit review process. With high levels of water or steam injection, turbines may experience increases in CO emissions. States may require oxidation catalysts to minimize CO emission levels.

MICHAEL J. BRADLEY, EXECUTIVE DIRECTOR
129 PORTLAND STREET
BOSTON, MASSACHUSETTS 02114
TEL. (617) 367-8540 FAX (617) 742-9162

III. Ammonia Emission Limit

Ammonia emissions or "slip" from an advanced nitrogen oxide control system should be maintained below 10 ppmv unless this emission limit is shown to be inappropriate. (Note 2 and 3)

IV. Other Recommendations

A. CEM and Process Monitoring Guidelines

1. NO_X CEM
   a. All projects where NOx is catalytically controlled
   b. All projects greater than 100 MMBtu/hr

2. Water/fuel ratio monitored in accordance with the applicable portions of NSPS Subpart GG when water or steam injection used for NOx control.

3. CO CEM for all projects greater than 100 MMBtu/hr or where CO is catalytically controlled.

4. Fuel flow meter with instantaneous and integrating output

5. Ammonia feed rate meter and determination of ammonia slip for all projects with an SCR system

6. Temperature before an SCR system and before and after an oxidation catalyst

B. Suitable back-up fuels include, but are not limited to, low Sulfur oil (less than 0.3%, or a lower level specified by a state limit), jet fuel, kerosene, methanol, propane, butane, refinery gas, or LPG. Back-up fuel is the fuel used when the primary fuel source is interrupted by the gas company when supply is limited.

C. Stack testing is required by the NSPS for nitrogen oxides (as NO_2) at four turbine load points including peak and minimum loads. Stack testing is suggested for carbon monoxide and hydrocarbons at peak and minimum loads.

D. While this recommendation includes emission limits for NO_x, CO and NH_3, applicants should be advised that state permits can include emission limits for other pollutants including, but not limited to, particulate matter and hydrocarbons. Consequently, there may be testing or other requirements for these pollutants.

E. This recommendation in no way relieves an applicant from complying with any applicable requirements of the new source performance standards contained in 40 CFR.

Notes:
1. Size categories are based on total heat input to the gas turbines on a per unit basis using lower heating values and ISO (International Standards Organization) conditions on a dry basis (without water injection). ISO conditions are 288°K, 60% RH, 101.3 kPa. MMBtu/hr refers to the heat input rate to the turbines in millions of British thermal units per hour.

2. The concentration limits above (in ppm) will have a corresponding mass emission rate (lb/h) in a permit based on worst case operating conditions. The averaging time for emission limits is one hour. Compliance is determined from actual emissions during testing. Operating conditions existing at testing may become enforceable permit conditions.

3. SCR or other advanced technology(s) may not be required, provided it is shown to be inappropriate for an oil or gas-fired turbine rated for greater than 100 MMBtu/hr. If SCR or other technologies are shown to be inappropriate, then the nitrogen oxide (NO_x) limit for that turbine should be the manufacturer's lowest guaranteed NO_x limit. It is possible that higher NO_x limits will be considered with corresponding decreases in NH_3 slip.

4. If supplementary fuel is fired, NO_x emissions for the duct burner must comply with the emission limits for the same category as the associated turbine. The turbine must be tested with and without operation of the duct burners. Operation of duct burners is subject to US EPA's New Source Performance Standards, Subpart D, Da, Db, or Dc and Subpart A, "General Provisions." contained in 40 CFR 60.

5. Installations of multiple units, each less than 100 MMBtu/hr, but totaling more than 100 MMBtu/hr, may be required to meet the emission standard for units larger than 100 MMBtu/hr.

6. Compliance with NO_x emission limits should be determined using EPA Method 20 or another approved method. Compliance with CO emission limits should be determined using EPA Method 10 or another approved method.

7. Local fuel conditions may dictate a modification of this limit depending on the level of fuel bound nitrogen. The 18 ppm limit in Section I.B. assumes the use of SCR and a fuel bound nitrogen content of up to 600 ppm.

This recommendation was approved by the NESCAUM Board of Directors on October 21, 1991 following a public comment period. The recommendation will be reviewed periodically and revised where appropriate.

NESCAUM STATIONARY SOURCE COMMITTEE
RECOMMENDATION ON EMISSION LIMITS FOR NEW COMBUSTION TURBINES

October 1991

Technical Support Memorandum

I. Introduction

One of NESCAUM's primary goals is to encourage regional consistency in approaches to plan reviews and consideration of control technologies. In April 1988, the NESCAUM Stationary Source Committee met to discuss gas turbine and cogeneration permits being reviewed by all of the air agencies. At that meeting, the Committee voted to send to the NESCAUM Board of Directors a recommendation for nitrogen oxide (NO_x) emission controls on gas turbines more restrictive than required by US EPA New Source Performance Standards. That original recommendation, approved by the NESCAUM Board of Directors in October 1988, is being revised as requested by the NESCAUM Board of Directors to consider advancements in emission control technology for combustion turbines which have occurred since 1988.

The NESCAUM states require "top-down" BACT determinations. Therefore, the Committee believes that the most stringent NO_x controls (usually referred to as the Lowest Achievable Emission Rate or LAER) available for stationary sources must be identified and considered in a BACT analysis. <u>The recommended emission limits are not, however, BACT for this source category.</u> BACT must be determined on a case-by-case basis. These emission limits should be considered in the BACT analysis, but are presumptive and do not dictate the permitted emission limit for a particular source. As with any BACT determination, "top-down" gives an applicant the right to show that the use of an advanced technology is not appropriate in a specific situation. The burden of proof is on the applicant for demonstrating that an alternative technology is appropriate.

This recommendation is directed primarily at NO_x emissions. The Committee recognizes that increasingly stringent NO_x emission limits can lead to increases in CO emissions. NH_3 emissions are also a concern with the use of SCR systems. The permit applicant should keep in mind that each state has the discretion to deviate from the recommended emission limits to achieve the appropriate environmental balance for their area using interpollutant tradeoffs.

Recognizing that advanced NO_x technologies, usually determined to be selective catalytic reduction (SCR), have been approved in an increasing number of applications in the region, the NESCAUM Directors have asked the Committee to continue researching five issues. Agencies must understand these issues and work with applicants to ensure that stringent emission control systems are installed. Four of these issues are: the size of turbines appropriate for stringent control measures, intermittent oil use (with resulting sulfur and nitrogen content) and its affect on catalyst life and guarantees, realistic amounts of ammonia (NH_3) slip from injection systems and controlling those emissions, and the cost of SCR systems at small and large facilities. One issue has been added to this version of the recommendation: advanced combustion control technology as an alternative to tail gas treatment. These technologies were prompted by developments in low NO_x combustor design.

The Committee recognizes that the Clean Air Act Amendments of 1990 will impose additional requirements for stationary source NOx control. Applicants are advised that the thresholds that trigger new source review for major sources, and major modifications, will be lowered according to an area's nonattainment classification. A source that is defined as a major source or major modification will be subject to new source review permitting requirements including lowest achievable emission rates (LAER) and offsets. Controls on existing sources of NO_x are also required by Section 182. States will be developing reasonably available control technology (RACT) regulations during 1992. An applicant should contact the individual state to determine the status of revised new source review or RACT regulations.

Note : All emission limits in ppmv reflect dry basis, corrected to 15% oxygen

II. Appropriate Cutpoints for Stringent NO_x Controls

The NESCAUM recommendation includes a 100 MMBtu/hr (approximately 10 MW) per unit cutpoint for considering advanced technology for NO_x control on gas turbines. Installations of multiple units, each less than 100 MMBtu/hr, but totaling more than 100 MMBtu/hr, may be required to meet the emission standard for units greater than 100 MMBtu/hr. Some EPA NSPS requirements (for example, Subpart Db), use a cutpoint of 100 MMBtu/hr. Units larger than this are required to meet a more stringent emission limit.) The Committee is concerned that the economics of installing SCR on small units could prompt some sources to switch to diesel engines from turbines, with resulting higher NO_x emissions. The Committee will continue to follow advances in NO_x control technologies for small turbines that could lead to emission levels approaching the levels achieved by larger turbines.

III. Intermittent Oil Use and Catalyst Life

A 1988 survey of U.S. SCR catalyst manufacturers examined catalyst life using fuels containing sulfur (coal and oil) revealed few installations in this country. The survey concluded that sulfur containing fuels would present a significant problem in promoting the use of SCR in the Northeast. (6)

However, information recently obtained from Japan (9, 13) and Europe shows that as of April 1986, SCR experience extended back 8.5 years on oil-fired boilers, 8.0 years on gas, and 6.5 years on coal. As of 1988, Japan had at least 22 SCR units for coal-fired boilers, 55 SCR units for oil-fired boilers, and 13 SCR units for LNG boilers. In general, figures show that with coal, SCR catalyst life is 2-3 years; oil-fired life is 4-7 years; and with LNG or gas, catalyst life is in excess of 6 years.

During the initial installations of SCRs, NO_x reductions were normally about 30%. The operating experience of more recent installations show reductions, in most cases, of 70-80%. When discussing SCR catalyst guarantees, manufacturers in the U.S. should consider the work done by the Japanese on catalyst availability.

A potential problem frequently cited regarding the use of sulfur containing fuels and SCR is the possible formation of ammonium sulfate salts, such as ammonium bisulfate (NH_4HSO_4). Sulfur trioxide (SO_3) in flue gas can react with ammonia and condense on the cooler surfaces of the heat recovery steam generator (HRSG) as ammonium sulfate salts. These salts can be very corrosive and therefore, concerns about cold end corrosion with the HRSG have been cited.

Problems with ammonium sulfate salt formation can be mitigated by:

1. Choosing an SCR catalyst composition that minimizes the conversion of SO_2 to SO_3, limiting the available SO_3 for reaction with the ammonia.
2. Operating the SCR unit to limit the ammonia slip through reduced ammonia injection.
3. Discussing the minimum catalyst inlet temperature to minimize NH_3 slip and limit formation of ammonium bisulfate. Typically, with 1 ppmvd SO_3 in the flue gas, problems with ammonium sulfate salt formation can be mitigated by maintaining a temperature of 575°F across the load range (14). In any case, an SCR system should not be operated outside the temperature range specified by the manufacturer.

An operating approach that minimizes the formation of ammonium sulfate salts is still capable of NOx reductions on the order of 70%. The Japanese have used this practice with their SCR systems that use sulfur bearing fuels. U.S. manufacturers can produce SCR catalysts capable of 80-90% NOx reductions with SO_2 conversions under 3% (14).

In summary, claims of manufacturers in this country of short catalyst life due to sulfur containing fuels are not borne out by Japanese experience during the last 8-10 years. Advances continue to be made and SCR should not be rejected as a viable control alternative due to fears of catalyst contamination from sulfur containing fuels. In addition, development of low sulfur fuels and sulfur resistant catalysts mitigates the argument against using SCR catalysts on oil-fired units.

IV. Carbon Monoxide Emission Limits

Since combustion turbines are "lean burn" engines (exhaust oxygen about 15% by volume), exhaust carbon monoxide (CO) emissions at rated load from conventional combustors without water or steam injection are typically:

10 ppmv for frame turbines
50 ppmv for aircraft derivative turbines

To conform to the nitrogen oxide recommendations of this policy, almost all commercial turbines will be water (or steam) injected which elevates carbon monoxide emissions. The air emissions control system must then be optimized to achieve the best environmental balance between NOx and CO. For example, New Jersey has required additional (SCR) catalyst to compensate for reduced water (steam) injection necessary to meet a 10 ppmv CO limit for larger units (greater than 40 MW).

Frame turbines typically steam inject to 42 ppmv NOx, 10 ppmv CO, and then use an SCR system to reach 9 ppmv NO_x. Steam injection to 25 ppmv NO_x results in CO of 25 ppmv which has not been acceptable in New Jersey.

V. Ammonia Use (2, 4, 12)

The Stationary Source Committee is concerned about releases of ammonia from NO_x control systems for two reasons. First, individual state permitting programs may require an analysis of ammonia use and the potential for releases. Second, if an agency determines that a project requires a PSD permit, then the June 1986 North County PSD remand in Region 9 (6) requires that the toxic effects of ammonia be included in the review. These hazards can be largely avoided by the use of aqueous ammonia.

There are two basic processes,thermal and catalytic, for using ammonia injection to control nitrogen oxide emissions from lean burn combustion equipment such as gas turbines. The thermal process (SNCR) is effective only at temperatures greater than approximately 1400°F although enhancers are being developed to allow operation at turbine exhaust temperatures. This is higher than normal gas turbine exhaust temperatures of approximately 1000°F and is achievable only by reheating the gas turbine exhaust in a device such as a duct burner. The catalytic process, SCR, operates in an optimum temperature window of approximately 650-850°F, a range which is normally achieved by cooling gas turbine exhaust in a heat recovery boiler. Catalysts are being developed to allow SCR operation at variable and higher exhaust temperatures. (1 and 14)

In either process, some unreacted ammonia passes through to the atmosphere. This unreacted ammonia is commonly referred to as ammonia "slip." Typically, the amount of ammonia slip can vary from almost zero, in a well controlled stable system with moderate conversion efficiency (less than 90%), to 30 ppmv or more in systems requiring very high conversion efficiencies or in poorly controlled or highly variable systems. Since the SCR process is much more prevalent and is readily adaptable to gas turbine exhaust conditions, the focus here is on ammonia slip from SCR controlled gas turbine emissions.

In the SCR process, the overall chemical reaction requires a theoretical molar ratio of NH_3:NO_2 of 1:1, although the reaction is complex because of the varying oxidation numbers of the different oxidized species of nitrogen present in the exhaust gas being treated. However, as is the case in many chemical reactions, the law of mass action requires an excess of the reagent, NH_3, to drive the reaction if high conversion efficiency is desired. Also, operating the SCR ammonia injection system at its theoretical limit is not practical due to imperfect mixing, local variations of concentrations in the reactor, and other factors. In practice, some amount of unreacted ammonia slip must be tolerated in the exhaust gas. Some of the factors that influence the amount of slip are:

1. control system lag and imperfect operation of instrumentation, continuous emission monitor problems, etc.
2. high temperature "hotspots" favoring oxidation of NH_3
3. low temperature areas resulting in incomplete or slow reactions
4. variations in NH_3 and NO_x concentration across the duct
5. incomplete mixing of ammonia with the exhaust gas
6. conversion of nitrogen to ammonia
7. variations in the quantity of exhaust gas due to load changes and sluggishness in achieving a new equilibrium set point in the control system.

In many gas turbine applications, the trade-off for the reduction in NO_x emissions may be the substitution of an equivalent amount of ammonia emissions. For example, a typical water-injected turbine may reduce NO_x to 50 ppmv and an add-on SCR unit would reduce NO_x to 9 ppmv. However, the exhaust gas may contain 10 ppmv of NH_3.

As of August 1988, three SCR controlled gas turbines in New Jersey had been permitted for maximum allowable ammonia emissions of 20-30 ppmv. An odor threshold for ammonia of 20 ppmv is supported by a review of the literature (3, 5). High conversion efficiencies (greater than 90%) and variable exhaust conditions typically result in ammonia slips of 20-30 ppmv. However, at a lower conversion efficiency (less than 90%) and stable operation, a 10 ppmv slip is achievable for SCR systems. In situations involving high conversion efficiencies, variable loads, or poorly responding control systems, an add-on ammonia decomposition catalyst may be needed to meet this limit. This recommendation states that ammonia slip from an advanced nitrogen oxide control system should be maintained below 10 ppmv unless this emission limit is shown to be inappropriate.

Ammonia CEM equipment is approaching commercial availability and some recent permits for large projects have included NH_3 monitors. At a state's discretion, CEM equipment for NH_3 could be required to be installed, maintained and operated when the agency determines that acceptable equipment is available.

VI. Cost of Controls

As of March 1991, there were at least 28 gas turbine projects in the NESCAUM region that either have permits and will use SCR technology or are proposing to use SCR technology to control emissions of nitrogen oxides. These 28 projects are estimated to generate a combined total of approximately 3816 MW of electrical power. By applying SCR technology to these 28 projects, potential reductions of more than 20,000 tons of NO_x per year are achievable. (8) These projects indicate that the cost-effectiveness for advanced NO_x control systems is considered "reasonable" compared to other NO_x controls being considered by the agencies.

The NESCAUM Directors approved the Stationary Source Review Committee's revised BACT Guideline in June 1991 (7). A copy can be obtained from NESCAUM. The purpose of this document is to promote consistent agency analysis of control technologies during BACT reviews. It is also intended to provide prospective applicants with guidance on conducting a BACT analysis. The document includes a discussion of cost calculations. For all turbine projects, an analysis of the cost of control options using a basis of dollars per ton of pollutant controlled should be conducted for each pollutant subject to BACT. This should be calculated using the total cost of the control technology system(s) divided by the total amount of controlled emissions, not just the incremental cost of any advanced emission control systems.

Combustion turbine emission control alternatives which should be considered (not necessarily in this order) are:

1. Low NO_x combustor
2. Increased steam injection with CO catalyst
3. SCR
4. Dual function catalyst (NO_x and CO).

VII. Advanced Combustion Control

Since October 1988, there have been advances in combustion control and for some turbines NO_x exhaust concentrations of approximately 9 ppmv at 15% oxygen are reported to be achievable with low NO_x combustors and steam or water injection. Also, SCR use on gas turbines has increased. All new or significantly modified projects with heat input over 100 million Btu's per hour should include a control technology analysis to consider turbines with advanced combustion control technology, water injection and SCR.

The NESCAUM states do not mandate tail gas treatment processes which involve ammonia injection if low emissions can be achieved by other means such as combustion control. One reason is that anhydrous ammonia is classified as a hazardous substance in some states. Unless significant emission reductions are achieved, the NESCAUM states are reluctant to mandate any technology which may present risk of catastrophic accident even if an acceptable risk management program can be incorporated. These hazards can be largely avoided by the use of aqueous ammonia. SCR processes result in unreacted ammonia (slip) which offset the NO_x reduction. For example, the NESCAUM states may consider 15 ppmv NO_x without SCR to be equivalent to 9 ppmv NO_x and 10 ppmv ammonia (slip) with SCR, assuming natural gas is used as the primary fuel. Nevertheless, if the project is affected by the PSD regulations or is greater than 100 million BTU per hour heat input, a thorough evaluation of SCR, low NO_x combustion, and other available methods capable of achieving NO_x emissions lower than 25 ppmv, should be evaluated in permit applications.

The Committee is aware that several combustion gas turbine manufacturers are presently developing dry or wet (water or steam injection) low NO_x combustors. These machines may be able to achieve an NO_x emission level of 25 ppmv or less, for natural gas fuel, without installing an SCR system. For example, the NJ DEP recently permitted two General Electric utility peaking Frame 7EA turbines, at 25 ppmv with natural gas fuel and water injection. General Electric is also working to develop a combustor capable of achieving single digit NO_x emissions dry on gas fuel (15).

The Committee is also aware of the following examples of advanced combustion technologies. The Pratt & Whitney Division of United Technologies Inc. is developing a dry low NO_x combustor for its model FT-8 (50 MW) gas turbine, that may be capable of achieving 25 ppmv with natural gas. Siemens Kraftworks Union model V84 (150 MW) is presently guaranteed at 25 ppmv NO_x with a dry low combustor firing natural gas. Asea Brown Boveri is also working on turbines capable of achieving less than 25 ppmv without an SCR unit. Westinghouse is offering a 100 MW turbine (model D-501D5) that can meet 25 ppmv with dry combustion technology.

The thermodynamic efficiency of the turbine is also a factor when considering advanced combustion controls. The NESCAUM states would like to encourage the use of high efficiency, low fuel use turbines that are also capable of achieving the recommended emission limits. A state may consider giving NO_x emission credits for higher combustion efficiency turbines in a BACT analysis if an air quality benefit is demonstrated. Future revisions to this document may consider formalizing an efficiency credit approach similar to that taken by the South Coast Air Quality Management District in Rule 1134 (August 1989).

VIII. Conclusion

The NESCAUM states are receiving and reviewing many applications for gas turbines which could represent large increases in NO_x emissions. The Stationary Source Committee believes that turbines are a significant new source of NO_x emissions in the region. Their significance, combined with the need to identify control technologies for use in the a "top-down" BACT process, leads the Committee to recommend very stringent emission limits for these sources. The four technical and policy issues discussed above - appropriate cutpoints for stringent NO_x controls, intermittent oil use and catalyst life, ammonia use, and cost of controls - can be resolved through appropriate design and operation of NO_x control systems. In addition, advances in combustion controls may lead to low NO_x levels without the use of catalysts. In order to meet the goals of the Clean Air Act of 1990, the NESCAUM states will need to achieve stringent NO_x controls on gas turbines and other stationary sources. Therefore, the states expect to follow the development of new control technologies and their ability to further lower permitted NO_x emissions.

This recommendation was approved by the NESCAUM Board of Directors on October 21, 1991, following a public comment period. The recommendation will be reviewed periodically and revised where appropriate.

VIII. Bibliography

1. Becker, Dr. E. Robert. Environex Short Course. Selective Catalytic Reduction of Nitrogen Oxides. Prepared for NESCAUM training course. Wayne, PA: Environex Inc. January 1991.

2. Champagne, D.L. January-February, 1988. SCR Cost Effective for Small Gas Turbines. Cogeneration. p.26-29.

3. Documentation of the Threshold Limit Values and Biological Exposure Indices, 5th Edition, American Conference of Governmental Industrial Hygienists, Inc.

4. Heck, R.M. et. al. 1987. Catalytic Air Pollution Controls-Commercial Development of Selective Catalytic Reduction for NO_x. Technical Paper No. 87-52.3, Englehard Industries. Air Pollution Control Association.

5. Journal of Applied Toxicology. 1983 Vol 3, Number 6. P. 272-292

6. New England Cogeneration Association. Selective Catalytic NOx Reduction Technology for Cogeneration Plants. Prepared by Arthur D. Little, Inc. November 1988.

7. Northeast States for Coordinated Air Use Management. June 1991. BACT Guideline.

8. Seidman, N.L., and McVay, D. L. Stationary Source Nitrogen Oxides Control Strategies in the Northeast States. Air and Waste Management Association 84th Annual Meeting and Exhibition. June 16-21, 1991, Vancouver, British Columbia, Canada. Paper #91-94.6

9. Suyama, K. 1985. Operating Experience on SCR System for Steam Generators. Mitsubishi Heavy Industries, Ltd., Nagasaki Shipyard and Engine Works, 1-1 Akunoura-Machi, Nagasaki, Japan.

10. Thomas, Lee M., Administrator, U.S. Environmental Protection Agency. June 1986. Remand to US EPA Region X. of PSD Appeal No. 85-2. North County Resource Recovery Associates.

11. U.S. Environmental Protection Agency. July 1987. New Source Performance Standards for Gas Turbines, Title 40 Code of Federal Regulations Part 60, Subpart GG, and Appendix A.

12. Winkler, D.G. September 12, 1985. Selective Catalytic Reduction and CO Oxidizer Process. ICS Cogeneration Workshop Series. Johnson Matthey, Inc.

13. Yasuyuki Nakabayashi and Ribiya Abe. April 1986. Current Status of SCR in Japan. Research and Engineering Office, Thermal Power Development, Electric Power Development Company, Ltd., Tokyo, Japan 100.

14. Connor, R.J., Industrial Gas Cleaning Institute, Inc. June 5, 1991. letter to N.L. Seidman, on the May 1991 proposed version of the NESCAUM Recommendation on Emission Limits for Combustion Turbines.

15. Shorr, M.M., General Electric Industrial and Power Systems. June 5, 1991. letter to N.L. Seidman, on the May 1991 proposed version of the NESCAUM Recommendation on Emission Limits for Combustion Turbines.

turb recmd-final