California Environmental Protection Agency

Air Resources Board

REPORT TO THE LEGISLATURE

GAS-FIRED POWER PLANT NOx EMISSION CONTROLS AND RELATED ENVIRONMENTAL IMPACTS

Stationary Source Division

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State of California

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AIR RESOURCES BOARD

Report to the Legislature

Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts

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ACRONYMS

ARB or Board	California Air Resources Board
ATC	Authority to Construct
BACT	best available control technology
CAPCOA	California Air Pollution Control Officers Association
CEC	California Energy Commission
CEMS	continuous emission monitoring system
CEQA	California Environmental Quality Act
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CTG	combustion turbine generator
DB	duct burners
district or air district	air pollution control or air quality management district
DLN	dry low-NOx combustors
gr	grains
gr/dscf	grains per dry standard cubic feet
H_2	molecular hydrogen
H_2O	water
HHV	higher heating value
HRSG	heat recovery steam generator
HSC	California Health and Safety Code
lb/day	pounds per day
lb/hr	pounds per hour
lb/MMBtu	pounds per million British Thermal Units
lb/MWh	pounds per megawatt-hour
MMBtu/hr	million British Thermal Units per hour
MW	megawatts
N_2	molecular nitrogen
NH_3	ammonia
NO	nitric oxide
NO_2	nitrogen dioxide
NOx	oxides of nitrogen
NSR	New Source Review
O_2	oxygen
OEM	original equipment manufacturer
PM10	particulate matter 10 micrometers in diameter and smaller
PM2.5	particulate matter 2.5 micrometers in diameter and smaller
ppmvd	parts per million by volume on a dry basis
RATA	relative accuracy test audit
RCRA	Resource Conservation and Recovery Act
SCR	selective catalytic reduction
San Joaquin Valley APCD	San Joaquin Valley Air Pollution Control District
scf	standard cubic feet
SIP	State Implementation Plan
South Coast AQMD	South Coast Air Quality Management District
SOx	oxides of sulfur
TAC	toxic air contaminant
tpd	tons per day
U.S. EPA	United States Environmental Protection Agency
VOC	volatile organic compound

I. EXECUTIVE SUMMARY

In the *Supplemental Report of the 2003 Budget Act 2003-04 Fiscal Year*, the Legislature directed the State Air Resources Board (ARB or Board) to investigate and provide a one-time report to the Governor and the Legislature by March 1, 2004, on control technologies that reduce oxides of nitrogen (NOx) emissions from gas-fired power plants and that do not use or produce toxic or hazardous materials *or* create other environmental impacts. The directive was included as Item 3900-001-0001 in the Budget Act Report and states the following:

***"Power Plant Emission Control Systems**. On or before March 1, 2004, the Air Resources Board shall report to the Legislature and the Governor on the benefits, detriments, and advisability of using technologies that reduce or eliminate NOx emissions from gas-fired power plants and that do not use or produce toxic or hazardous materials or create other significant adverse environmental impacts. This report shall be prepared in consultation with the appropriate policy and fiscal committees of the Legislature, air districts, and the public."*

Stakeholder Participation

As stated, the Legislature required the ARB to develop this report in consultation with the appropriate policy and fiscal committees of the Legislature, air districts, and the public. Staff made conscious efforts to ensure that the appropriate stakeholders were aware of, and had an opportunity to participate in, the report development process. ARB staff's public outreach efforts involved contact and/or interaction with:

- Government agencies (California Legislature, California Energy Commission, California air pollution control and air quality management districts, California Independent System Operator, United States Environmental Protection Agency);
- Industry (basic equipment vendors, energy consultants, emission control equipment vendors, power producers);
- Organizations (Institute of Clean Air Companies, Independent Energy Producers, American Lung Association of California, Natural Resources Defense Council, California Council for Environmental and Economic Balance); and
- other interested parties.

Staff contacted over 400 affected parties (including individuals and organizations) by one or more of the following means: telephone, electronic mail, or regular mail. In addition, staff developed and regularly updated (with list serve notification) a web page (http://www.arb.ca.gov/energy/noxlegrpt.htm) describing the report, its status, and contact information. Primary outreach activities included:

- site visit to a power plant to observe a gas turbine equipped with the SCONOx™ catalytic absorption system;
- survey of 20 NOx emission control system vendors requesting environmental impact and cost data for gas turbine power plants [Note: feedback via survey was limited to

five respondents representing selective catalytic reduction (SCR), Xonon Cool Combustion™ catalytic combustor, Low Emissions Combustor Liner, and SCONOx];

- survey of power plant operators to obtain feedback on the performance and operation of SCR;
- discussion of the report with representatives of the California Air Pollution Control Officers Association (CAPCOA); and
- Public Consultation Meeting.

A draft of the report was made available for public comment prior to finalization.

Scope of the Report

Considering the Legislature's intent and consulting with affected stakeholders, ARB staff determined that the report should focus on a particular segment of the power generation sector. The following summarizes the major components:

- Electrical generating units at fossil gas-fired power plants may consist of boilers, turbines, or reciprocating engines. Recent activity in the electrical generation sector in California has consisted primarily of the construction of large new power plants comprised of simple- or combined-cycle turbines fueled by natural gas. For the purposes of this report, gas-fired power plants are defined to include new installations of natural gas-fired turbine electrical generating power facilities with capacities of 50 megawatts (MW) and greater.

- California has one of the most effective New Source Review programs in the country, with requirements for advanced emission control technology on new and expanding sources as its foundation. Therefore, this report focuses on NOx control technologies that can meet or assist in meeting emission levels currently established as best available control technology (BACT) by California air regulatory agencies. The current BACT level for NOx emissions from natural gas-fired electrical generation turbines is $\leq$2.0 parts per million by volume on a dry basis at 15 percent oxygen (ppmvd at 15% O_2) and $\leq$3.0 ppmvd at 15% O_2 for cogeneration/combined-cycle and simple-cycle power plants, respectively.

Use of the Report

This report is intended to be used strictly as an informational document, providing an overview of available NOx emission control technologies for natural gas-fired turbine power plants (herein "gas turbines") and a description of some of the auxiliary environmental impacts that may be considered when evaluating power plant projects. The report is not intended to establish new BACT emission levels or certify or validate any emission levels purported to be achieved at various facilities. In addition, the report is not intended to be used as a substitute for a California Environmental Quality Act (CEQA) review or any other environmental analysis required by a regulatory agency in accordance with applicable laws, ordinances, regulations, or standards.

Findings

This report does not include conclusions or recommendations. Instead, it provides information that can be used as a starting point in conducting more detailed site-specific analyses of the environmental advantages and disadvantages of control technologies that reduce NOx emissions from natural gas-fired power plants. The research performed and data collected to complete this report have provided the following findings for further consideration in conducting such evaluations:

Emission Control Methods and BACT

- The SCONOx catalytic absorption system produces beneficial NOx, carbon monoxide (CO), and volatile organic compound (VOC) emission reductions without the associated environmental impacts from ammonia use and can achieve emission levels required as BACT in California. At this time, the system has been demonstrated on smaller turbine applications (=43 MW).

- Selective catalytic reduction (SCR) in conjunction with an oxidation catalyst produces beneficial and comparable NOx, CO, and VOC emission reductions as SCONOx and can achieve emission levels required as BACT in California. Auxiliary environmental impacts from SCR are associated with the use of ammonia.

- Lean premix combustors are effective up-front pollution prevention devices but cannot currently achieve the level of NOx emissions required as BACT in California.

- Lean premix combustors in conjunction with SCONOx or SCR have demonstrated the ability to achieve the progressive NOx emission levels required as BACT in California.

- The Xonon Cool Combustion system has shown to be an effective pollution prevention device that can achieve NOx emission levels required as BACT in California for both simple-cycle and combined cycle gas turbine power plants without the associated environmental impacts from ammonia use; however, the technology has limited applications at this time.

- The Low Emission Combustor III Liner is a relatively new aftermarket pollution prevention device without the associated environmental impacts from ammonia use. Initial installations have shown the ability to achieve sub-5 ppmvd NOx emission levels, which may satisfy BACT requirements in some cases. A testing and validation program is under way to refine the device to achieve NOx emissions equivalent to BACT without the need for post-combustion emission control. Currently, the technology is more marketable as a retrofit control technology. It is limited to specific turbine types but is expanding its base.

Environmental Impacts

- Where ammonia and particulate matter emissions are a concern, elimination or minimization of ammonia slip or application of an ammonia catalyst is an option.

- Depending on the types and quantities of constituents, spent SCR catalysts may be considered hazardous wastes. However, there are programs in place to manage the catalysts by recycling components or disposing of the catalysts in approved landfills.

- With respect to the hazards associated with anhydrous and aqueous ammonia, it appears there is no compelling reason not to use SCR for NOx emission control unless there are unusual circumstances specific to a power plant site that would deem ammonia use a high-risk alternative.

Cost of Control

- Available cost data indicates that SCR used in conjunction with an oxidation catalyst costs less than SCONOx for the same level of emissions reduction. More detailed cost comparison information is presented in Chapter V.

II. CALIFORNIA POWER GENERATION AND AIR QUALITY PROFILE

A. Power Generation in California

According to the California Energy Commission (CEC), the total electricity demand in California in 2002 was nearly 275,000 gigawatt-hours (GWh), or an average of approximately 31,000 megawatts (MW) output throughout the year. The infrastructure in place to meet this demand consists of power plants with a total installed capacity of 55,800 MW within California and another 6,200 MW of capacity located in Arizona, Nevada, Utah, and New Mexico owned by California utilities. As shown in Table II-1, the highest percentage of electricity is generated in fossil fuel-fired power plants. Of this in-State "fired" generation capacity, 57 percent is produced by boilers, 42 percent by combustion turbines, and one percent by reciprocating internal combustion engines.

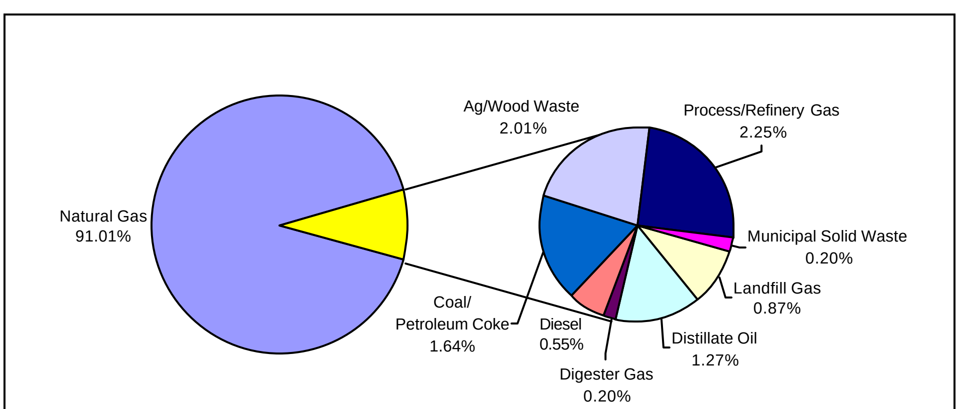
Table II-1. California Generation (Operational plant of 0.1 MW and greater)

Unit Type	No. of Plants	Online Capacity (MW)	Percentage of Capacity
Coal	15	549.5	1.0%
Geothermal	46	2,562.0	4.8%
Hydroelectric	386	14,117.0	26.2%
Nuclear	2	4,310.0	8.0%
Oil/Gas	343	28,962.0	53.8%
Solar	14	412.6	0.8%
Wind	104	1,815.0	3.4%
Waste-to-energy	102	1,083.0	2.0%
	1,012	53,811.1	

Source: California Energy Commission, 2001 Database of California Power Plants

Natural gas plays a dominant role in California's fuel-fired generating system and is the preferred fuel because of its cleaner combustion characteristics compared to other fuels. Natural gas has negligible sulfur, which limits sulfur compound emissions; negligible ash, which limits particulate matter emissions; and NOx emission rates that are generally lower than from other fuel types. The mixture of fuel-fired resources that provide electric energy to the State is shown in Figure II-1.

Figure II-1. California In-State Fuel-Fired Generation



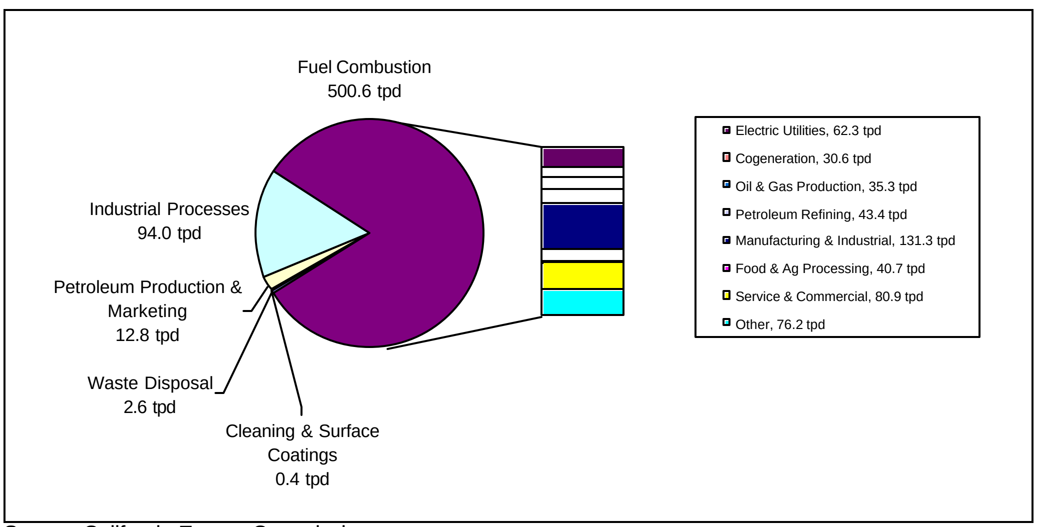
Source: California Energy Commission

The passage of Assembly Bill 1890 (Statutes of 1996, Chapter 854) deregulated the electric utility industry in California and prompted an increase in new power plant construction. The majority of these projects have consisted of large plants (500 MW and greater) producing electricity using stationary combustion turbines fueled with natural gas and equipped with state-of-the-art air pollution control technologies. Since 1999, the CEC has approved power plant applications totalling 15,767 MW—of these, 8,311 MW have come online since 2000. Additional projects amounting to about 5,200 MW are currently under review at the CEC; another 780 MW have been publicly announced.

B. Power Plant NOx Emissions

Traditionally, the pollutant of most concern from gas turbines is NOx. NOx emissions are of particular concern due to their contribution to ground-level ozone formation and acid rain. In the lower atmosphere, NOx combines with reactive organic gases in the presence of sunlight to form ground-level ozone, which is the primary component of urban smog. In addition, nitric oxide and nitrogen dioxide are components of acid rain. Figure II-2 contains the most recent estimates (2002) of annual average daily NOx emissions (tons per day, or tpd) from all stationary sources in California. The fuel combustion category is the largest NOx contributor at 82 percent of total emissions. Within the fuel combustion category, power-generating units contribute about 19 percent of NOx emissions from all fuel burning sources (electric utilities and cogeneration subcategories). For comparison, the estimated NOx emissions from all mobile sources in the State are 2,696 tons per day, versus 501 tons per day for all fuel combustion stationary sources.

Figure II-2. 2002 Statewide Estimated Annual Average NOx Emissions from Stationary Sources



Source: California Energy Commission

Over 85 percent of the fuel-fired generating units have some level of NOx control employed and almost 60 percent use SCR for NOx emission control. Emission controls employed on fuel-fired turbines are summarized in Table II-2. Approximately 93 percent of turbines have some level of NOx control.

Table II-2. California Power Generating Turbine NOx Emission Control Technologies

Type of Control System	No. of Units	Capacity (MW)
Gas Turbines		
Selective Catalytic Reduction or SCR (includes units that have other up-front controls such as DLN)	183	8,620.0
SCONOx	3	68.8
Xonon Cool Combustion	1	1.5
Dry Low-NOx Combustors	31	1,427.9
Steam Injection	17	970.8
Water Injection	138	2,296.0
Uncontrolled	27	517.9
	400	13,903

Source: Air Resources Board Power Plant Database

C. Regulation of Emissions

Air quality regulations limit emissions from new pollutant sources through performance standards and requirements to obtain emission reductions from existing sources through the use of retrofit technologies. Regulations require the installation of control devices, fuel use restrictions, operational limits, offsetting of emission increases, and caps on total emissions from a source.

New Source Review and Best Available Control Technology

New Source Review (called NSR) is a preconstruction permitting program that regulates new and existing sources that emit or have the potential to emit any pollutant (or precursor) above specific thresholds for which there is a State or federal ambient air quality standard. Best available control technology (BACT) is the cornerstone of the program—requiring a new or expanded source to meet the most stringent emission level achievable by current technology. NSR rules allow growth while minimizing emissions. Emission increases that remain after the application of BACT are offset with reductions in emissions at existing sources to result in no net increase in emissions.

In 1999, the Board adopted the *Guidance for Power Plant Siting and Best Available Control Technology*. The guidance is a non-regulatory document intended to assist the local air quality management and air pollution control districts (air districts) in making permitting decisions as they participate in the CEC's power plant siting process. The guidance helps ensure that new gas turbine power plants employ BACT and are constructed and operated in a way that eliminates or minimizes adverse air quality impacts. The BACT emission levels recommended by ARB staff in the guidance are summarized in Table II-3. Using the guidance as a benchmark, the emission control technologies described in this report are those that have the ability to meet or are an integral component in meeting California BACT emission levels for natural gas-fired turbine power plants. It should be noted that the recommended BACT emission levels in Table II-3 were considered to be contemporaneous with the publishing of ARB's guidance and are subject to change if operational data or advances in technology demonstrate that lower levels have been achieved or are achievable at a reasonable cost. Since adoption of the guidance, ARB staff believes electrical generation gas turbines can meet lower levels.

Table II-3. Summary of BACT for Gas Turbine Power Plants of 50 MW and Greater

NOx	CO	VOC	PM10	SOx	NH_3
Combined-Cycle and Cogeneration Configurations					
2.5 ppmvd @ 15% O_2, 1-hour rolling average OR 2.0 ppmvd @ 15% O_2, 3-hour rolling average	6 ppmvd @ 15% O_2, 3-hour rolling average	2 ppmvd @ 15% O_2, 1-hour rolling average OR 0.0027 lb/MMBtu (HHV)	Emission limit corresponding to natural gas with fuel sulfur content ≤1 gr/100 scf		≤5 ppmvd @ 15% O_2
Simple-Cycle Configurations					
5 ppmvd @ 15% O_2, 3-hour rolling average	6 ppmvd @ 15% O_2, 3-hour rolling average	2 ppmvd @ 15% O_2, 3-hour rolling average OR 0.0027 lb/MMBtu (HHV)	Emission limit corresponding to natural gas with fuel sulfur content ≤1 gr/100 scf		≤5 ppmvd @ 15% O_2

III. EMISSION CONTROL METHODS

This chapter focuses on five pollutant control technologies that reduce NOx emissions from electrical generation natural gas-fired turbines. For each control technology, a description of how the device works and a summary of emission performance capabilities are provided. As mentioned previously, the control technologies described in this chapter are those that have the ability to meet or that facilitate meeting the ARB's recommended BACT emission levels for power plant gas turbines.

A. Selective Catalytic Reduction

Selective catalytic reduction (SCR) of NOx using ammonia as the reducing agent was first patented in the United States in the 1950s. In California, SCR is the most widely developed and applied post-combustion NOx control technology for power plants. The Institute of Clean Air Companies (ICAC) reports that more than 100 systems have been installed in combined-cycle gas turbine applications in the United States since 1986.

1. Technology Description

Selective catalytic reduction is a post-combustion control technology capable of reducing NOx emissions by about 80 to 95 percent. Selective catalytic reduction systems selectively reduce NOx by combining ammonia (NH_3) and oxygen (O_2) with NOx in the turbine exhaust gas in the presence of a catalyst to form molecular nitrogen (N_2) and water (H_2O). The primary chemical reactions are shown below.

Chemistry of the SCR Process

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The catalyst, comprised of parallel plates or honeycomb structures, is installed in the form of rectangular modules, downstream of the gas turbine in simple-cycle configurations and into the heat recovery steam generator (HRSG) portion of the gas turbine downstream of the superheater in combined-cycle and cogeneration configurations. A typical SCR system is comprised of an ammonia storage tank, vaporization and injection equipment for ammonia, a booster fan for the flue gas, a SCR reactor with catalyst, and instrumentation and control equipment.

The turbine exhaust gas must contain a minimum amount of oxygen and be within a particular temperature range in order for the SCR system to operate properly. The temperature range is dictated by the catalyst, which is typically made from noble metals, base metal oxides, or zeolite-based material. Typical temperature ranges for SCR catalysts are shown in Table III-1. Keeping the exhaust gas temperature within these ranges is important. If it drops below, the reaction efficiency becomes too low and increased amounts of NOx and ammonia will be released out the stack. If the reaction temperature gets too high, the catalyst may begin to decompose. Turbine exhaust gas is generally in excess of 1000 °F. Heat recovery steam generators cool the exhaust gases before they reach the catalyst by extracting energy from the hot turbine exhaust gases and creating steam for use in other industrial processes or to turn a steam turbine. In simple-cycle power plants where no heat recovery is accomplished, high temperature catalysts that can operate at temperatures up to 1050 °F, are an option.

Table III-1. Typical Operating Temperatures for SCR Catalysts

Catalyst	Temperature Range (°F)
Platinum	350-500
Vanadium	575-850
Zeolite	650-1050

2. Emission Performance

The majority of gas turbine power plants installed in California since 1999 have utilized turbines equipped with dry low-NOx combustors in conjunction with SCR to achieve the required BACT emission level for NOx. A sampling of permitted NOx emission limits for facilities employing SCR for NOx control is given in Table III-2. Information on additional facilities, as well as permit limits for other pollutants and required controls, is included in Appendix A.

Table III-2. Recent NOx Limits for Gas Turbine Power Plants Using SCR

Permit Limit (at 15% O_2)	Configuration	Control Technology	Permit Issuance Date	Facility Name and Location	Status
2.0 ppmvd	CC	SCR	9/29/99	Sithe Mystic Development LLC, Everett, MA (1,550 MW)	Operating
2.0 ppmvd	CC	Dry low-NOx combustors with SCR	5/21/99	Lake Road Generating Co., Killingly, CT (840 MW)	Operating
2.0/3.5 ppmvd	CC	SCR	3/16/01	ANP Blackstone, Blackstone, MA (550 MW)	Operating
2.5 ppmvd	SC	Water injection with SCR	2/2/02	Wallingford Energy, Wallingford, CT (225 MW)	Operating
2.5 ppmvd	SC	Water injection with SCR	NA	New York Power Authority/Hell Gate, Bronx, NY (94 MW)	Operating
3.5 ppmvd	SC	Water injection with SCR	4/11/01	West Springfield Redevelopment Project, West Springfield, MA (84 MW)	Operating

CC: Combined Cycle, SC: Simple cycle

Combined-Cycle and Cogeneration Gas Turbines

The most stringent NOx BACT limit established for an operational combined-cycle or cogeneration gas turbine is 2.0 parts per million by volume on a dry basis at 15 percent oxygen (ppmvd at 15% O_2) averaged over 1 hour with ammonia slip limited to 2.0 at

15% O_2. This NOx emission level was first achieved at ANP Blackstone in Blackstone, Massachusetts, on two 180-MW ABB GT-24 gas turbines equipped with SCR. These units have been operating since mid-2001.

On April 16, 2003, the South Coast Air Quality Management District (South Coast AQMD) established new BACT emission levels for combined-cycle and cogeneration gas turbines of 2.0 ppmvd NOx and 3.0 ppmvd CO at 15% O_2, 1-hour average. The BACT levels were determined to be achieved-in-practice based on operating data from the ANP Blackstone site. Source test data from 2001 and 2002 accepted by the Massachusetts Department of Environmental Protection showed compliance with the permit limits, except for a July 2001 50-percent load test on Unit 2 that exceeded the PM10 limit. Unit 2 was retested in December 2001 and was well below the limit. Results of certified continuous emissions monitoring system (CEMS) data available from U.S. EPA's Acid Rain web site for the first three quarters of 2002 showed NOx in compliance with the 2.0 ppmvd limit with very few exceptions during over 2,300 hours of operation of Unit 1 and over 3,700 hours of Unit 2. More exceedances were observed during the first year of operation; however portions may have been representative of commissioning activities.

Emission test data results for ANP Blackstone as well as other similar power plants indicate compliance with NOx emissions of 2.5 ppmvd at 15% O_2 or less through the application of SCR in conjunction with dry low-NOx combustors. Available source test data results are summarized in Appendix B Table B-1.

Simple-Cycle Gas Turbines

The most stringent NOx BACT limit for an operational simple-cycle gas turbine is 2.5 ppmvd at 15% O_2 averaged over 1 hour with ammonia slip limited to 6 ppmvd at 15% O_2 averaged over 3 hours. This NOx limit is required in the permit for Wallingford Energy in Wallingford, Connecticut, on five 45-MW GE LM6000 gas turbines. The turbines are equipped with water injection and SCR for NOx control and have been operating since 2001. The Connecticut Department of Environmental Protection stated that the facility had initial problems meeting the NOx and ammonia slip limits concurrently, but reported that those problems have been fixed and the units now run in compliance.

Emission test data for similar power plants indicate compliance with NOx emissions of 5 ppmvd at 15% O_2 and less through the application of SCR in conjunction with water/steam injection or dry low-NOx combustors. Source test data results available from representative plants are included in Appendix B Table B-2.

It should be noted that most recent simple-cycle gas turbine power plant installations are comprised of single or multiple aeroderivative-type turbines.[1] Aeroderivative turbines have lower exhaust temperatures (about 750-975 °F) than their larger industrial frame turbine counterparts (as high as about 1100 °F); therefore frame turbines are a common choice for combined-cycle and cogeneration plants because of the superior thermal efficiency. As a result, there is much less experience with application of SCR on industrial frame turbines in simple-cycle configuration.

Exhaust air cooling has been used on many simple-cycle aeroderivative turbine applications to lower exhaust gas temperatures below 900 °F, so a vanadium catalyst can be used (less expensive than zeolite). Air cooling is not as widely used on frame machines. Although theoretically feasible, SCR system suppliers and power plant proponents report it is not practical to cool an 1100 °F exhaust down to the range where a combined-cycle system catalyst operates. The higher volume of air added creates the need for flow straightening devices/baffles due to mixing/stratification issues. No major technical feasibility issues have been cited from using high-temperature SCR with a *minimal* level of exhaust cooling. The ARB's *Guidance for Power Plant Siting and Best Available Control Technology* states case-by-case BACT determinations may be warranted for simple-cycle gas turbines with higher exhaust temperatures (i.e., industrial frame turbines).

Operator Experience

ARB staff conducted a phone survey of gas turbine power plant operators in the State at sites employing SCR for NOx reduction. ARB staff contacted 46 facilities and received feedback from the representatives of 32 sites. The purpose of the survey was to obtain feedback on the overall performance of SCR systems. In terms of emissions, operators reported that the SCR systems have been performing as guaranteed by the manufacturers. In the majority of responses, the catalyst has lasted considerably longer than the three-year guarantees that are typical in today's market—the average catalyst life was about nine years, with the longest going on 16 years. Over half of the operators cited no environmental issues or concerns with the SCR system. About one-third of the operators stated the most significant environmental concern with the SCR system is dealing with ammonia (both aqueous and anhydrous); though of these, no one reported any major incidences with ammonia handling and storage or experienced problems with system operation. There were concerns expressed regarding ammonia slip emissions, and the creation of a new pollutant (i.e., secondary particulate matter) from the attempt to reduce NOx (see discussion in Chapter IV). Lastly, a couple of operators relayed concerns about spent catalyst disposal and maintaining consistency and accuracy in emissions and measurement due to the low levels required to meet BACT in California.

[1] As the name suggests, aeroderivative turbines were adapted to land applications from aircraft engine designs. Because there are weight and size limitations for aircraft, aeroderivative turbines tend to be lighter weight. Industrial frame-type turbines tend to be larger, more rugged, and better suited to base-load operation.

3. Concurrent Reduction of CO and VOC Emissions

Time of fuel dispensation, peak pressures, and combustion and exhaust temperatures all affect NOx formation. There typically is an inverse relationship between the formation of NOx and CO. Higher combustion temperature and pressure levels, which are often conducive to NOx formation, tend to be out of the range of ideal CO forming conditions. If conditions within the chamber cool, NOx emissions come down, but CO and hydrocarbons may rise in the form of an incomplete burn. Therefore, plants using lean premix combustors in conjunction with SCR for NOx reduction typically utilize an oxidation catalyst to concurrently meet BACT emission levels for CO and VOCs.

At this time, only two areas in California are designated nonattainment for the State CO ambient air quality standards: Los Angeles County[2] and the City of Calexico in Imperial County. CO violations arise primarily from concentrated motor vehicle emissions. Nevertheless, district rules that require BACT for CO from gas turbines have generally required the application of an oxidation catalyst to achieve single-digit emission concentrations.

a. Technology Description

In catalytic oxidation, a catalyst is used to oxidize CO at lower temperatures. The addition of a catalyst to the basic thermal oxidation process accelerates the rate of oxidation by adsorbing oxygen from the air stream and CO in the waste stream onto the catalyst surface to react to form carbon dioxide (CO_2) and water. Typical control efficiencies from an oxidation catalyst are from 80 to 90 percent.

Like CO emissions, VOC emissions have traditionally been abated with combustion controls and oxidation catalysts. In addition, due to low VOC emission concentrations, the control of VOC emissions from gas turbines was relatively unimportant to regulators compared to those of NOx and CO. As a result, initial control of VOC experienced with oxidation catalysts was more coincidental than intentional since the oxidation catalysts were initially utilized to control CO.

b. Emission Performance

Permitted emission limits have generally been at 6 ppmvd at 15% O_2 or less for CO and 2 ppmvd at 15% O_2 or less for VOC (see Appendix A). Available source test data shows CO measurements in compliance with 6 ppmvd or less, with many results less than 1 ppmvd at 15% O_2. At least two power plants had initial problems meeting VOC permit limits but were able to demonstrate compliance upon subsequent retest. Results from current operating installations are given in Appendix B.

[2] The Board approved changes to area designations on January 22, 2004, deeming it nonattainment-transitional.

B. SCONOx™ Catalytic Absorption System

SCONOx is a post-combustion, multi-pollutant control technology, originally developed by Goal Line Environmental Technologies (now EmeraChem LLC).[3] Alstom Power offers SCONOx for commercial sale and is the primary supplier for larger turbine installations. WahlcoMetroflex is also a supplier of SCONOx. The technology is capable of reducing emissions by approximately 90-95 percent for NOx and 90 percent for CO. Control efficiency for VOCs has varied, although there may be potential to control VOC up to 90 percent. The VOC emission guarantee is determined on a case-by-case basis based on the constituents in the exhaust gas.

1. Technology Description

The SCONOx system uses a single catalyst to remove NOx, CO, and VOC emissions in the turbine exhaust gas by oxidizing nitrogen oxide (NO) to nitrogen dioxide (NO_2), CO to CO_2, and hydrocarbons to CO_2 and water, and then absorbing NO_2 onto the catalytic surface using a potassium carbonate (K_2CO_3) absorber coating. The potassium carbonate coating reacts with NO_2 to form potassium nitrites and nitrates, which are deposited onto the catalyst surface. SCONOx does not use ammonia; therefore there are no ammonia emissions from this catalyst system. The reactions are shown below.

Chemistry of the SCONOx Process

$$NO + 1/2O_2 \rightarrow NO_2$$
$$CO + 1/2O_2 \rightarrow CO_2$$
$$CH_2O + O_2 \rightarrow CO_2 + H_2O$$
$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3$$

The SCONOx system is installed downstream of the gas turbine after the HRSG; whereas the SCR catalyst is installed within the HRSG in combined-cycle and cogeneration power plants. The optimal temperature window for operation of the SCONOx catalyst is from 300-700 °F. Therefore, the system is not currently offered for simple-cycle configurations.

Regeneration Cycle

When all of the potassium carbonate absorber coating has been converted to nitrogen compounds, NOx can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen reducing gas (H_2) across the surface of the catalyst in the absence of oxygen. Hydrogen in the gas reacts with the nitrites and nitrates to form water and molecular nitrogen. Carbon dioxide in the gas

[3] SCONOx™ is the trade name originally used by Goal Line. EMx™ is the second-generation of the SCONOx technology available through EmeraChem. Because the operating principle is the same, this report uses SCONOx to describe applications of both the original SCONOx catalyst and the improved EMx catalyst.

reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst.

Regeneration Reaction

$$KNO_2 + KNO_3 + 4H_2 + CO_2 \rightarrow K_2CO_3 + 4H_2O(g) + N_2$$

The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam reforming catalyst. The reformer catalyst initiates the conversion of methane (CH_4) to hydrogen. The reformer catalyst is located upstream of the SCONOx catalyst in a steam reformer reactor. The SCONOx reactor is composed of modules that contain multiple sections. Each section has a set of louvers that alternately close and seal each section of the module front and back for regeneration.

During regeneration, the operation of the SCONOx catalyst at temperatures below 500 °F may produce small amounts of hydrogen sulfide. Operation of the catalyst at temperatures above 500 °F may result in small amounts of sulfur dioxides. These emissions are typically below 5 percent of the Public Utilities Commission’s set limit for sulfur.

SCOSOxÒ Catalyst

The SCONOx catalyst is sensitive to contamination by sulfur in the combustion fuel. The SCOSOx catalyst is provided in conjunction with the SCONOx system as a “guard bed” to remove sulfur compounds from the gas turbine exhaust stream. It is nearly identical to the SCONOx catalyst, except that it favors sulfur compound adsorption. The SCOSOx catalyst blocks are placed upstream of the SCONOx catalyst. The SCOSOx system uses the same oxidation/absorption and regeneration cycle as the SCONOx system. The regeneration gas used for the SCONOx and SCOSOx catalysts is the same, allowing them to be regenerated simultaneously.

A typical SCONOx system is comprised of a catalyst rack and reactor housing with SCONOx and SCOSOx catalysts, catalyst module inlet and outlet dampers, regeneration gas production and distribution system, regeneration gas condensing and scrubbing system (optional), catalyst removal system, and instrumentation and control equipment.

Figure III-1. Cross-Section of SCONOx System

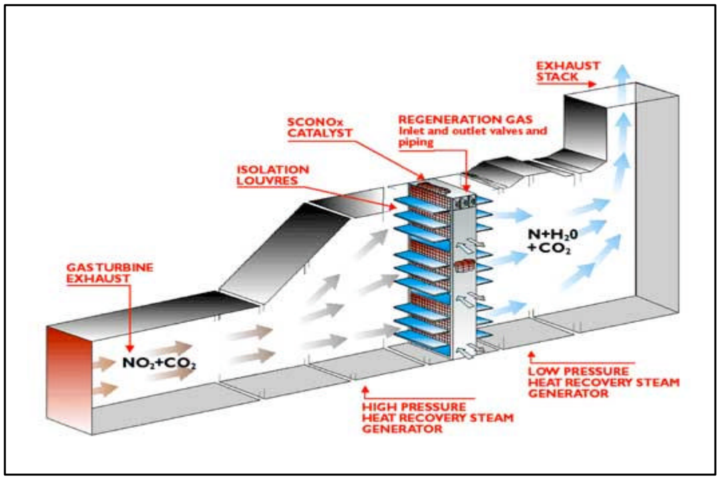


Photo: Courtesy of Alstom Power

2. Emission Performance

The SCONOx system is installed at a total of seven sites in the United States. The permitted NOx emission limits for these facilities are given in Table III-3. Additional information on emission limits and controls is summarized in Appendix A Table A-1. Results from selected installations are described below.

Table III-3. NOx Limits for Combined-Cycle and Cogeneration Gas Turbine Power Plants Using SCONOx

Permit Limit (at 15% O_2)	Control Technology	Size (MW)	Online Date	Facility Name and Location	Status
9 ppmvd	Water injection with SCONOx	32	12/28/96	Federal Cogeneration, Los Angeles, CA	No longer in service
2.5 ppmvd, 15.0 ppmvd (oil)	Dry low-NOx combustors with SCONOx	6.2	07/1/99	Wyeth Bio Pharma #1 (Genetics Institute), Andover, MA	Operating
2.5 ppmvd	SCONOx	26	July 01	University of California San Diego, San Diego, CA	Operating
2.5 ppmvd	SCONOx	43	June 02	City of Redding Power Plant, Redding, CA	Operating
2.5 ppmvd, 15.0 ppmvd (oil)	Dry low-NOx combustors with SCONOx	5.9	2003	Wyeth Bio Pharma #2, Andover, MA	Operating
2.5 ppmvd, 15.0 ppmvd (oil)	Dry low-NOx combustors with SCONOx	5.2	NA	Montefiore Hospital, Bronx, NY	NA
4 ppmvd target	SCONOx	8	Installed June 01	Los Angeles International Airport, Los Angeles, CA	Control system shut down

Installation Experience

Federal Cogeneration

SCONOx was first demonstrated commercially at Federal Cogeneration in Los Angeles commencing on December 28, 1996. The facility consisted of a 32-MW General Electric LM2500 gas turbine at a cogeneration plant. Initially, six months of CEMS data from June to December 1997 were reviewed by the United States Environmental Protection Agency (U.S. EPA) and the South Coast AQMD. In a March 23, 1998, letter, the U.S. EPA deemed 2.0 ppmvd NOx at 15% O_2 averaged over 3 hours as demonstrated in practice. The South Coast AQMD subsequently determined BACT as 2.5 ppmvd NOx at 15% O_2 averaged over 1 hour.[4] Operating data from Federal Cogeneration set a precedent that future combined-cycle and cogeneration gas turbine projects subject to BACT must consider 2.5 ppmvd when making their BACT determination for NOx emissions. The SCONOx system is no longer in operation at this site, because the entire plant shutdown in 2003 due to market factors.

Wyeth Bio Pharma (Genetics Institute) Unit 1

The system serving the Unit 1 generating turbine at Wyeth Bio Pharma in Andover, Massachusetts, has been in operation since July 1, 1999. This installation operates at 650 °F to treat the exhaust gases from a Solar Taurus 60 gas turbine (6.2 MW) at a cogeneration plant. Natural gas is the primary fuel; however, the turbine is also permitted to use distillate fuel, which is fired during curtailment periods. Initially, when the turbine operated for long periods of time using oil, the SCONOx catalyst experienced sulfur masking problems that reduced the effectiveness of the NOx reductions. The masking was reversible, but required washing of the catalyst and therefore, shutdown of the turbine. The conditional permit included an 18-month commissioning period wherein the facility could continue to fine-tune the system to achieve the 2.5 and 15.0 ppmvd NOx at 15% O_2 limits when firing natural gas and distillate fuel, respectively. During that time, EmeraChem made modifications to the SCONOx system such that oil usage no longer adversely affects the catalyst. The Massachusetts Department of Environmental Protection reports that the turbine is meeting its permit limits when firing natural gas and oil.

University of California San Diego

The system at the University of California San Diego has been in operation since July 2001. This installation operates at 420 °F to treat the exhaust gases from two Solar SoLoNOx Titan 130S gas turbines (26 MW) at a cogeneration plant. Initially, the facility was under a variance with the San Diego County Air Pollution Control District—the turbines passed the start-up source test, but failed their Relative Accuracy Test Audit

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[4] NOx limits of 2.0 and 2.5 ppmvd at 15% O_2 with 3- and 1-hour averaging times, respectively, are generally recognized by California regulatory agencies as equivalent.

(RATA).[5] The facility installed a multi-point probe and subsequently passed the test. The plant operator reports that the permit limits are being met, but that maintenance is more extensive than originally estimated. Quarterly CEMS reports from October 2002 through September 2003 indicate no excess NOx emissions. The plant operator reports NOx measurements meet the 2.5 ppmvd at 15% O_2 permit limit between catalyst washings, which are currently conducted about every four months. During the wash process, the plant is down for about three days. The facility has determined that emission levels are best met when all three layers of catalyst are washed, not just the leading layer. Overall, the facility is pleased with the emissions performance, and they attribute the more frequent washing to the engineering design of the regeneration system (e.g., gas leaks and inefficiencies in regenerating sulfur from the SCOSOx guard bed). Based on experience from this site, EmeraChem has improved the regeneration system design.

City of Redding

The system at the City of Redding Power Plant in Redding, California, has been in operation since June 2002 and has accumulated approximately 8,300 hours of run time. This installation operates at 600 °F to treat the exhaust gases from an Alstom Power GTX 100 gas turbine (43 MW) at a combined-cycle plant. Redding Power owns the dampers but has a 15-year lease agreement on the catalyst from Alstom. As such, Alstom is in charge of ongoing catalyst maintenance. The Shasta County Air Quality Management District reports that there have been no major compliance issues in meeting the 2.5 ppmvd at 15% O_2 NOx permit limit. To date, the SCONOx catalyst has required washing about three times per year, and the SCOSOx catalyst has not yet required washing. The wash process is generally completed over a weekend. The SCONOx reactor contains three layers of SCONOx catalyst. Since installation, the leading layer of SCONOx catalyst has been replaced—the second and third layers are the originals.

Los Angeles International Airport

The system at the Los Angeles International Airport is currently shut down and is the subject of litigation. This installation proposed to treat the exhaust gases from two Allison 501-KB5 dual fuel turbines (4 MW each). Natural gas was the primary fuel with fuel oil used as backup only. The turbines are existing units that fall under an emissions cap and have exhaust emissions of 40 ppmvd at 15% O_2. The system was proposed as a voluntary control measure; therefore BACT was not required. However, NOx emissions after treatment with SCONOx were targeted at 4 ppmvd at 15% O_2.

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[5] The RATA is essentially an on-site analyzer comparison test between the CEMS analyzers and those used by a RATA testing company. Both systems sample the same source and the results are subjected to statistical analysis and compared. The average accuracy of the CEMS analyzer relative to the RATA analyzer must be within a specific percentage.

C. Turbine-Integrated Controls

The control technologies described in this section are integrated into the basic turbine equipment. While these technologies cannot currently meet California NOx BACT requirements on their own, they are pollution prevention devices that help achieve BACT emission levels by reducing the creation and amount of pollutants that would otherwise be released prior to post-combustion treatment.

1. Lean Premix Combustors

a. Technology Description

The combustor is the space inside the gas turbine where fuel and compressed air are burned. Conventional combustors are diffusion controlled—meaning fuel and air are injected into the combustor separately and mix in small, localized zones. These zones burn hot and produce more NOx. In contrast, lean premix combustors (also often referred to as dry low-NOx combustors, or DLN, which GE pioneered in the early 1990s) minimize combustion temperatures by providing a lean premixed air/fuel mixture, where air and fuel are mixed before entering the combustor. This minimizes fuel-rich pockets and allows the excess air to act as a heat sink. The lower temperatures reduce NOx formation.

b. Emission Performance

At this time, GE Power Systems is the only manufacturer to offer a large frame-type gas turbine with DLN combustors that can achieve single-digit NOx emissions (i.e., ≤9 ppmvd at 15% O_2). Other power systems manufacturers sell gas turbines equipped with lean premix combustors, but those units emit NOx in the 15-25 ppmvd range. Table III-4 contains a sampling of gas turbines that are available with lean premix combustors and their corresponding exhaust NOx emission levels. The reader should note that an aftermarket combustor is available that can achieve single-digit NOx emissions (see discussion in Section III.C.3.).

Table III-4. NOx Emissions from Gas Turbines with Lean Premix Combustors

OEM	Gas Turbine Model	Approximate Output (MW)	Typical NOx Emissions (ppmvd at 15% O_2)
Solar Turbines	SoLoNOx Titan 130S	13	<15
Pratt & Whitney	FT4-C Twin Pac	49	15
GE	LM6000	48	25
GE	Frame 7-1E/EA	85	9/25
GE	Frame 7-1FA	171.7	9
Alstom Power	GT24B	188	<25
Alstom Power	GT26B	280.9	<25

Lean premix combustors alone cannot yet meet the current 2.5 ppmvd or less BACT requirement for NOx—prompting the need for post-combustion control systems such as

SCR and SCONOx. However, reduction of NOx emissions at the outset via lean premix turbines has facilitated achieving the low NOx levels currently required as BACT in California and elsewhere in the United States. Emission source test results from three GE Frame 7FA-type gas turbines equipped with DLN combustors are included in Appendix B Table B-2. Measured average emissions were less than 8 ppmvd NOx, less than 1.5 ppmvd CO, and less than 1 ppmvd VOC at 15% O_2.

2. Xonon Cool CombustionÔ Catalytic Combustor

Catalytica Energy Systems (spun-off from Catalytica, Inc. in December 2000 as a stand-alone public entity) first discovered and began applying for patents for its Xonon Cool Combustion technology in the late 1980s. Xonon utilizes a catalyst integrated into the gas turbine combustor to limit temperature below the temperature where NOx is formed. It also yields low CO and VOC emissions.

Each Xonon combustor is customized to the particular turbine model and application and is defined through a collaborative effort with the turbine original equipment manufacturer (OEM) to integrate the hardware into the design. Xonon is currently only commercially available from Kawasaki Gas Turbines-Americas on a small 1.4 MW gas turbine.

a. Technology Description

The Xonon Cool Combustion technology limits the formation of NOx emissions before they can form. Fuel is partially combusted in the catalyst followed by complete combustion downstream in the burnout zone. Partial combustion in the catalyst produces no NOx, because the catalyst limits the temperature in the combustor and helps stave off the production of NOx. Some fuel is combusted in the preburner to raise the compressed air temperature.

Figure III-2. Schematic of Xonon Cool Combustion Technology System

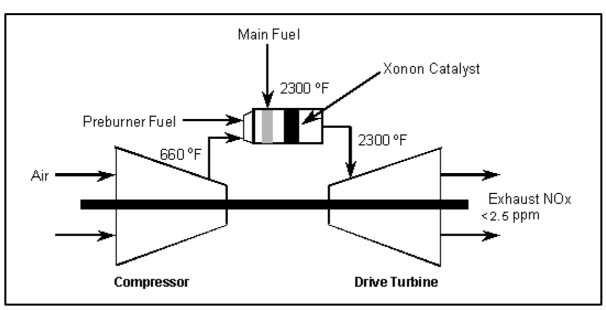


Photo: Courtesy of Catalytica Energy Systems

b. Emission Performance

Xonon is installed or under construction at a total of five sites in the United States. The permitted NOx emission limits for these facilities are given in Table III-5. Results from operating installations are described below.

Table III-5. NOx Limits for Combined-Cycle/Cogeneration Gas Turbine Power Plants Using Xonon

Permit Limit (at 15% O_2)	Control Technology	Online Date	Facility Name and Location	Status
5 ppmvd	Xonon cool combustion	1999	Silicon Valley Power, Santa Clara, CA (1.4 MW)	Operating
20 ppmvd	Xonon cool combustion	Nov. 2002	Sonoma Development Center, Eldridge, CA (1.4 MW)	Operating
3.0 ppmvd	Xonon cool combustion	Nov. 2003	Plains Exploration & Production Company (1.4 MW)	Operating
NA	Xonon cool combustion	NA	Pacific Union College, Angwin, CA (1.4 MW)	Under construction
3 ppmvd	Xonon cool combustion	NA	Readers Digest Association, Pleasantville, NY (1.4 MW)	Under construction

Silicon Valley Power

The Xonon system was first designed into the combustor of a 1.4 MW Kawasaki Model M1A-13A gas turbine and began operating at Silicon Valley Power in Santa Clara, California, in 1999. Since its installation, the turbine has operated as a demonstration of Xonon's performance and as a development and test unit in support of commercial program initiatives for customers. More than 18,000 hours of Xonon performance data has been accumulated on the demonstration unit.

Performance claims have been verified by the U.S. EPA through the Environmental Technology Verification (ETV) Program. U.S. EPA reviewed test results from the Silicon Valley Power facility conducted in July 2000 and verified the NOx emission results given in Table III-6.

Table III-6. U.S. EPA ETV Program Verification Statement of Xonon NOx Control Performance

Ambient Temperature Range	Percent of Full Turbine Load Range	Mean Outlet NOx Concentration ppmvd @ 15% O_2	Half-Width of 95% Confidence Interval on Mean Outlet NOx ppmvd at 15% O_2
59-77 °F	98-99%	1.13	0.026

The ARB also analyzed performance claims through its Equipment and Process Precertification Program. The ARB staff reviewed NOx and CO CEMS data from June 15, 1999 to December 16, 1999, from the same facility. Data reviewed included

15-minute and 1-hour rolling average emission values, including startup and shutdown periods. After evaluating all the test data, ARB staff concluded that Xonon achieved a NOx level of 2.5 ppmvd at 15% O_2 and a CO level of 6.0 ppmvd at 15% O_2, over a 1-hour rolling average at 98 percent or greater operating load of design capacity.

Sonoma Developmental Center

This system was a retrofit and has been operating since November 2002 in Eldridge, California. This installation consists of a Kawasaki MIA-13X (1.5 MW) gas turbine at a cogeneration plant. The modification did not trigger New Source Review, so the previous BACT limits were retained: 20 ppmvd NOx and 50 ppmvd CO at 15% O_2, averaged over 3 consecutive hours. The expected performance was 3 ppmvd NOx and 10 ppmvd CO. The manufacturer reports that the unit has consistently achieved continuous NOx emission levels below the emission target—on the average, NOx emissions are under 2.0 ppmvd at 15% O_2.

Plains Exploration & Production Company

This system was a new installation and represents the first complete commercial installation. It has been operating since November 2003 in San Luis Obispo, California. This installation consists of a Kawasaki GPB15X (1.4 MW) gas turbine at a cogeneration plant. The permitted limits are 3.0 ppmvd NOx, 10.0 ppmvd CO, and 2.0 ppmvd VOC at 15% O_2, over a 3-hour rolling average. The manufacturer reports that the unit has consistently achieved continuous NOx emission levels below the permit limit—on the average, NOx emissions are around 0.8 ppmvd at 15% O_2.

c. Commercial Availability

As a result of a collaborative agreement announced in December 2000, Kawasaki Gas Turbines-Americas markets and sells a GPB15X generator package including a 1.4-MW M1A-13X gas turbine equipped with Xonon. Kawasaki will provide a performance guarantee for NOx of 3.0 ppmvd and 10.0 ppmvd at 15% O_2 on a continuous basis over a 70-100 percent turbine operating load.

On April 25, 2001, Catalytica Energy Systems announced the shipment of full-size, pre-commercial Xonon catalyst modules to GE Power Systems. The modules have been undergoing testing at Nuovo Pignone (a GE Power Systems business) in Florence, Italy, in support of commercial delivery of GE10 gas turbines (11.3 MW) equipped with Xonon. Currently, there is no firm timeline for commercial delivery of a GE10 turbine with Xonon.

In October 2001, Catalytica Energy Systems entered into an agreement with Solar Turbines for adaptation of Xonon to the Solar Taurus 70 gas turbine. The first Xonon test module was delivered to Solar in December 2002 in preparation for initial testing during 2003.

3. Low Emissions Combustor (LEC-III^{TM}) Liner

Power Systems Manufacturing LLC, a subsidiary of San Jose, California based Calpine Corporation, has developed its proprietary Low Emissions Combustor III (LEC-III^{TM}) liner that produces single-digit NOx and CO emissions without post-combustion controls.

a. Technology Description

The LEC-III^{TM} liner is a patented aftermarket system designed to be a “drop-in” replacement for existing GE frame gas turbine combustors outfitted with either diffusion or DLN combustors. Power System’s lean, premixed combustion design involves premixing of fuel and air in the combustion system through innovative fuel gas injection methods and liner design. A forward-cooling flow venturi (the flame holder) in the combustion liner injects spent cooling air directly into the liner’s head end premixing chamber—reducing CO spikes at machine part load conditions. In addition, efficient cooling of the combustion liner is achieved through effusion cooling, where over 5,000 dimensionally controlled holes arrayed around the head end of the liner eliminate the need for thermal barrier coating. This improves cooling air requirements, aides in fuel/air mixing, and provides a more uniform thermal environment. The liner design allows for excellent heat transfer performance, low metal temperatures, and reduced NOx and CO emissions.

b. Emission Performance

The LEC-III^{TM} liner system was first installed in an existing 70-MW GE Frame 7EA gas turbine at TransAlta Cogeneration in Alberta, Canada, in 2001. Prior to the retrofit, the lowest emission levels from the turbine were reported at 17 ppmvd NOx and 14 ppmvd CO at 15% O_2. After installation of the LEC system, emission levels of 6 ppmvd NOx and 2.5 ppmvd CO (average) at 15% O_2 were measured. The turbine has since undergone a 24,000-hour major overhaul, which included removal and return of the hardware to the manufacturer for refurbishment. Reinstallation is planned for September 2004.

The second installation of the LEC-III^{TM} liner system occurred in March 2003 at Dow Chemical’s Power 8 facility in Freeport, Texas, on an 83-MW GE Frame 7EA gas turbine. The manufacturer offered an 8-ppmvd NOx guarantee with a design target of 5 ppmvd at 15% O2. Testing was conducted in April 2003 and emission levels of 4.75 ppmvd NOx at 15% O_2 were reported while the turbine was operated without duct burners. During duct burner firing, NOx emissions were between 6.75 to 9.09 ppmvd at 15% O_2, all with CO emissions below 1 ppmvd at 15% O_2. NOx emissions over the entire premixed operation gas turbine load range were below 5 ppmvd at 15% 0_2

Two additional units will go into service in Texas in 2004.

c. Commercial Availability

The product is offered commercially for the GE Frame 7E/EA (85.4 MW) and GE 6B (42.1 MW) turbines. The guaranteed NOx and CO emission concentrations in the exhaust are 5 ppmvd at 15% O_2 for both pollutants. The system is under development for the Siemens Westinghouse 501D5 gas turbine (173 MW). Additional development programs in 2004 involve the use of hydrogen-fuel blending to help drive emissions down to 2 ppm NOx as well as continued work on LEC systems for the GE 7FA (170 MW) and Siemens Westinghouse 501FD2 (283 MW) machines.

D. Zero-SlipÔ Ammonia Reduction Technology

A new control technology called Zero-Slip technology has been developed for simultaneous control of NOx and ammonia emissions from combined-cycle gas turbine power plants. This system is being jointly demonstrated and offered for commercial sale by Cormetech and Mitsubishi Power Systems.

1. Technology Description

The system consists of a layer of conventional SCR catalyst followed by the Zero-Slip catalyst. Ammonia is injected into the combustion turbine exhaust through the ammonia injection grid (AIG). The exhaust continues through an optional static mixer to reduce non-uniformities and then flows through the SCR and Zero-Slip catalysts. Vendors report ammonia slip reduction to zero with NOx reductions of 90 percent and higher. The Zero-Slip catalyst consists of layers for both denitration and ammonia oxidation balanced to achieve zero ammonia slip. The net reactions are shown below.

Zero-SlipÔ Catalyst Reaction

$$NO + NH_3 + 1/4O_2 \rightarrow N_2 + 3/2H_2O$$

$$NH3 + 5/4O_2 \rightarrow NO + 3/2H_2O$$

2. Emission Performance

The first commercial demonstration of the Zero-Slip system is currently in operation at Paramount Petroleum Corporation, located in Paramount, California, within the jurisdiction of the South Coast AQMD. Paramount Petroleum is a natural gas-fired cogeneration plant consisting of a 7.5-MW Solar Taurus 70S gas turbine equipped with dry low-NOx combustors and a duct-fired HRSG. Emission controls include an oxidation catalyst, SCR catalyst, and the Zero-Slip catalyst. The turbine’s permitted emission limits are 2.5 ppmvd NOx, 6 ppmvd CO, 2 ppmvd VOC, and 5 ppmvd ammonia, at 15% O_2 averaged over 60 minutes. The plant has been online for approximately one year.

Initial startup source tests measured VOC emissions in excess of the permitted limit. The facility was granted a variance by the South Coast AQMD and has conducted a series of follow-up tests to pinpoint the problem. Measurements taken across each catalyst in the series showed a possible recombining of hydrocarbons across the various catalyst beds—particularly a consistent VOC emissions increase across the Zero-Slip catalyst. However after further investigation, facility representatives found lube oil contamination in the turbine and duct burner and determined this to be the likely cause of the problem. The contamination is being corrected and the facility anticipates they will have source test results in April 2004. Although VOC emissions initially exceeded permit levels due to the suspect contamination, CO and NOx emissions levels have been below permit limits. In addition, the NH_3 emission level was measured at 0.1 ppmvd or less, which is also well below the permit level of 5 ppmvd.

IV. ENVIRONMENTAL IMPACTS

This chapter is intended to provide an overview of potential environmental impacts associated with the use of NOx emission control technologies for gas-fired turbines. While characterized as the cleanest of all the fossil fuels, the combustion of natural gas itself produces both criteria and toxic air pollutants (see Table IV-1). The impacts described herein are those environmental effects directly related to the use of the NOx control equipment.

NOx emission control technologies that are integrated into the combustion turbine itself can be considered pollution prevention equipment, because they reduce or eliminate the creation and amount of pollutants that would otherwise be released into the environment. The reduction of pollutants up-front lessens the hazards to public health and the environment associated with the release of such substances. ARB staff did not identify any substantial auxiliary environmental impacts from controls that are built into the combustion turbine unit. Therefore, the discussion focuses on potential environmental impacts associated with the post-combustion control systems, SCR and the SCONOx catalytic absorption system.

Table IV-1. Toxic Air Contaminants, Hazardous Air Pollutants, and Criteria Pollutants from Natural Gas Combustion in Turbines

TAC/HAP	Adverse Health Effects
Chlorine	Respiratory, eye, and skin irritant; possible asthma exacerbation.
Formaldehyde	Eye and respiratory irritant, asthma exacerbation, decreased pulmonary function, probable carcinogen.
Benzene	Hematotoxic, carcinogen.
Nickel	Respiratory irritant, dermatitis, asthma.
Manganese	Neurotoxicity, developmental toxicity.
Cobalt	Respiratory irritant, cardiac effects, immunological effects.
Chromium	Contact dermatitis, skin and nasal irritant, bronchitis, asthma, developmental effects, carcinogen.
Toluene	Respiratory and eye irritant, central nervous system depressant.
Acetaldehyde	Respiratory irritant, possible asthma exacerbation, probable carcinogen.
N-Hexane	Mild central nervous system effects, polyneuropathy.
M-Xylenem O-Xylene	Respiratory, eye, nose, and throat irritant; central nervous system depressant; possible gastrointestinal effects.
Ethylbenzene	Respiratory, eye, nose, and throat irritant; central nervous system depressant.
Criteria Pollutant	**Adverse Health Effects**
Ozone (precursors, NOx and VOC)	Eye and respiratory irritant, asthma exacerbation, bronchitis, lung damage.
Oxides of nitrogen	Respiratory irritant, immunosuppressant, asthma exacerbation.
Carbon monoxide	Headache, irritability, impaired judgement and memory, breathlessness, aggravation of angina and other cardiovascular diseases, developmental toxicity.
Particulate matter	Respiratory irritant; high levels associated with increased incidence of cardiovascular and lung failure in elderly, asthma in children.

A. Selective Catalytic Reduction

1. Ammonia Slip

As described in Chapter III, SCR uses ammonia as a reducing agent in the process of controlling NOx emissions from gas turbines. The portion of the unreacted ammonia passing through the catalyst and emitted out of the exhaust stack is called “ammonia slip.”

Ammonia as a Toxic Air Emission

Ammonia is not a federal hazardous air pollutant or a State identified toxic air contaminant. However, due to acute and chronic non-cancer health effects, ammonia is potentially regulated under air district risk management programs. Such programs may include toxic New Source Review rules or policies and the requirements of the Air Toxics “Hot Spots” Program (California Health and Safety Code §44360 et seq.). Ammonia is listed under the Hot Spots Program, and therefore, sources are required to report the quantity of ammonia they routinely release into the air. Gas turbines using SCR typically have been limited to 10 ppmvd at 15% O_2 ammonia slip. However, levels as low as 2 ppmvd at 15% O_2 have been proposed and guaranteed by control vendors, and the ARB recommends that air districts evaluate slip limits of 5 ppmvd at 15% O_2 or less.

Ammonia as a PM2.5 Precursor

Ammonia reacts with other pollutants to produce particulate matter. Ambient fine particulate matter (known as PM2.5) is composed of a mixture of particles directly emitted into the air and particles formed in air from the chemical transformation of gaseous pollutants (secondary particles). Principle types of secondary particles are ammonium sulfate and ammonium nitrate, which form in air from gaseous emissions of sulfur oxides and NOx, reacting with ammonia.

With the exception of the South Coast AQMD, ammonia is not currently regulated by air district New Source Review rules. New Source Review rules regulate criteria pollutants and their regulatory precursors. Although ammonia is recognized to contribute to ambient particulate matter concentrations, it is not listed in any California New Source Review rule as a precursor to PM10. As a result, air districts have regulated ammonia since the mid-1980s under nuisance and toxic air contaminant rules.

Prompted by the promulgation of new national ambient air quality standards for PM2.5 in 1997 and the establishment of a new State annual PM2.5 standard in June 2002 (effective July 5, 2003), the ARB has been working to assess the extent of and primary source contributors to the fine particulate matter problem in California.

PM2.5 Nonattainment Areas

Under the federal Clean Air Act, states must develop plans, known as State Implementation Plans (SIPs), describing how and when they will attain the national ambient air quality standards. State PM2.5 area designation recommendations are due to U.S. EPA in February 2004 and U.S. EPA will finalize designations by December 2004. A nonattainment designation means that the State must submit its SIP to U.S. EPA within three years after final designations are made (in 2007). ARB will recommend four nonattainment areas for the federal PM2.5 standards: South Coast, San Joaquin Valley, San Diego, and the City of Calexico.

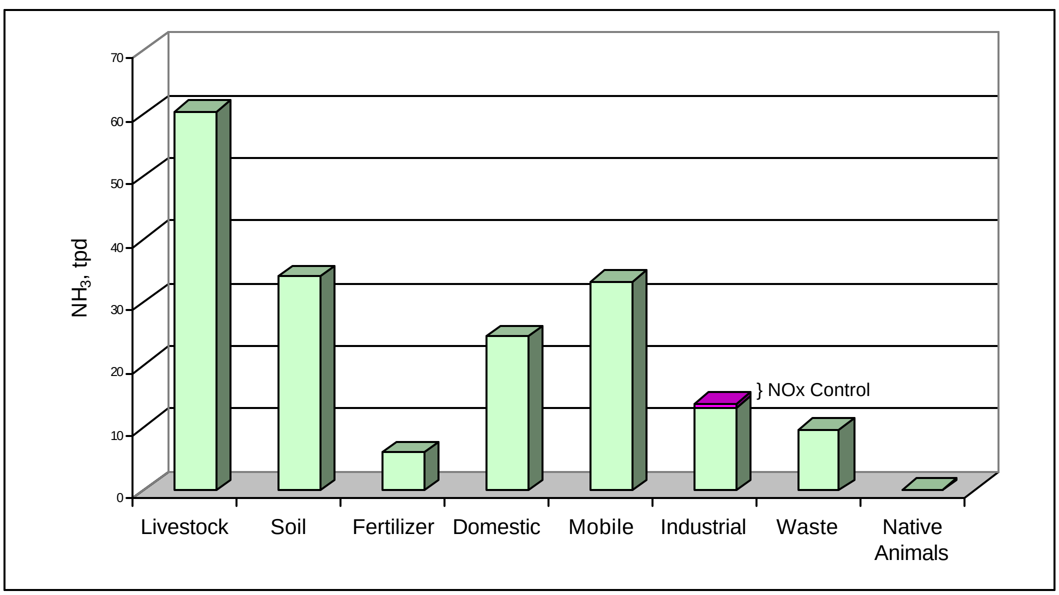
State law does not require air districts to prepare plans for attaining PM standards, but does require that they adopt rules and regulations to attain them as expeditiously as possible. On January 22, 2004, the Board adopted new State area designations for PM2.5 and changes to existing State area designations for ozone, CO, and sulfates. The only attainment area for PM2.5 is the Lake County Air Basin (see Appendix C for PM2.5 area designations for all California air basins).

Ammonia Inventory

Most regions with air quality concerns have already estimated emissions for the particulate matter precursor gases—NOx, oxides of sulfur (SOx), and VOC—however they do not have estimates of ammonia emissions. The ARB has been working on developing a comprehensive ammonia inventory, and has developed preliminary emission inventories from most potential ammonia sources in the State. Most of the potentially significant sources of ammonia are area-wide sources such as livestock, fertilizer application, and soils.

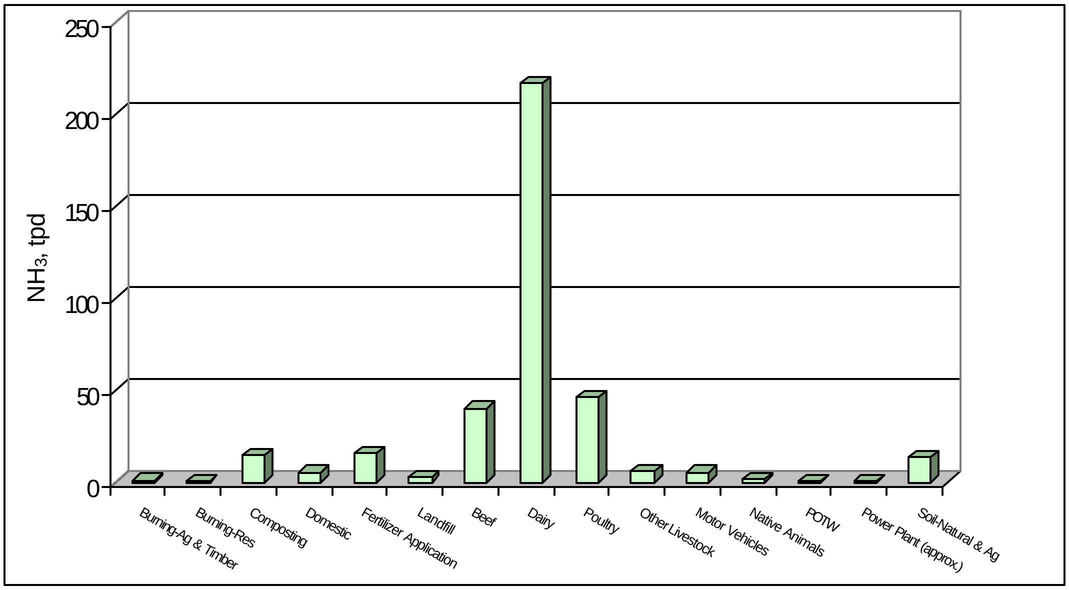
Regarding ammonia slip from power plant NOx emission controls, the estimates show this to be a relatively minor source of ammonia. For example, in the South Coast, the power plant related ammonia emissions are estimated at 0.6 tons per day, or 0.3 percent of the total ammonia emissions (see Figure IV-1). In the San Joaquin Valley, the power plant related ammonia emissions are approximately 0.6 tons per day, or 0.2 percent of the total ammonia emissions (see Figure IV-2).

Figure IV-1. Year 2000 Ammonia Inventory for South Coast AQMD (tons per day)



Source: Final 1997 Gridded Ammonia Emission Inventory Update for the South Coast Air Basin; prepared by AVES, ENVIRON, and others for the South Coast AQMD; August 2000.

Figure IV-2. Year 2000 Ammonia Inventory for San Joaquin Valley APCD (tons per day)



Source: Primary data developed from: California Regional PM10/PM2.5 Air Quality Study, Ammonia Emission Improvement Projects in Support of CRPAQS, Aerosol Modeling and Data Analyses, and Draft Ammonia Inventory Development; ENVIRON International Corporation; September 6, 2002.

Work is still ongoing on the ARB's fine particulate matter program, which includes expanded air quality monitoring, emission inventory improvements, development of improved air quality models, and comprehensive field studies to more accurately assess the relative contribution of various emission sources to the measured ambient PM2.5 levels.

Air districts should consider the impact of ammonia slip on meeting and maintaining PM10 and PM2.5 standards, particularly in regions where ammonia is the limiting factor in secondary particulate matter formation. Where a significant impact is identified, air districts could revise their respective New Source Review rules to regulate ammonia as a precursor to both PM10 and PM2.5.

2. Ammonia Handling and Storage

Every SCR system must utilize some form of ammonia reagent. Typical sources are anhydrous ammonia (concentrated ammonia stored as a liquid under pressure) and aqueous ammonia (mixture of ammonia with water, usually 19-29% ammonia by weight). Both anhydrous and aqueous ammonia are on the California list of acutely hazardous materials. The handling and storage of hazardous materials are regulated under numerous federal, State, and local laws that require certain process safety, accident prevention, emergency planning, and release reporting of hazardous materials. Table IV-2 contains a sampling of laws pertaining to the handling and storage of hazardous materials.

Table IV-2. Hazardous Material Laws, Ordinances, Regulations, and Standards

Laws, Ordinances, Regulations, and Standards	Description and Applicability
Federal	
Comprehensive Environmental Response, Compensation, and Liability Act/Superfund Amendment and Reauthorization Act (CERCLA/SARA) Section 302	Requires certain planning activities when Extremely Hazardous Substances are present in excess of their Threshold Planning Quantity (TPQ).
CERCLA/SARA Section 304	Requires notification when there is a release of hazardous material in excess of its Reportable Quantity.
CERCLA/SARA Section 311	Requires a Material Safety Data Sheet (MSDS) for every hazardous material to be kept on site and submitted to the State Emergency Response Commission, Local Emergency Planning Committee, and the local fire department.
CERCLA/SARA Section 313	Requires annual reporting of releases of hazardous materials.
Clean Air Act	Requires a Risk Management Plan (RMP) if listed hazardous materials are stored at or above a Threshold Quantity.
Clean Water Act	Requires preparation of a Spill Prevention Control and Countermeasures (SPCC) Plan if oil is stored above certain quantities.
State	
Hazardous Materials Release Response Plans and Inventory Act (HSC §25500 et seq.)	Requires preparation of a Hazardous Materials Business Plan if hazardous materials are handled or stored in excess of threshold quantities.
California Accidental Release Prevention (CalARP) Program (HSC §25531-25543.4)	Requires registration with local Certified Unified Program Agency (CUPA) or lead agency and preparation of a RMP if acutely hazardous materials are handled or stored in excess of their TPQ.
Aboveground Petroleum Storage Act	Requires entities that store petroleum in aboveground storage tanks in excess of certain quantities to prepare a SPCC Plan.
Safe Drinking Water and Toxics Enforcement Act (Proposition 65)	Requires warning to persons exposed to a list of carcinogenic and reproductive toxins and protection of drinking water from same toxins.
Local	
Uniform Fire Code	Controls storage of hazardous materials and wastes and the use and storage of flammable/combustible liquids.

Since 1999, the CEC has approved over 30 gas turbine power plant projects using SCR for NOx emission reduction (see Table IV-3). Most sites selected aqueous ammonia as the reagent to lessen the associated risk. In these cases, the combination of regulatory requirements and proposed mitigation strategies was determined to be adequate to reduce the potential risk of public health impacts due to any accidental release not addressed by a project's proposed spill prevention mitigation measures. With respect to hazards associated with ammonia, it appears there is no compelling reason not to use SCR for NOx control unless there are unusual circumstances specific to a facility that would make ammonia use a high-risk option.

Table IV-3. Post-Combustion NOx Control Technologies for Gas Turbine Power Plants Approved by the California Energy Commission since 1997*

Project	Size (MW)	Air District	NOx Control Technology	Ammonia Source	Status
Sutter Power Plant	540	Feather River	SCR	Anhydrous	Operating since July 2001
Los Medanos	555	Bay Area	SCR	Aqueous	Operating since July 2001
Delta	887	Bay Area	SCR	Anhydrous	Operating since May 2002
Moss Landing	1,060	Monterey	SCR	Aqueous	Operating since July 2002
La Paloma	1,124	San Joaquin Valley	SCR	Aqueous	Operating since March 2003
High Desert	830	Mojave Desert	SCR	Aqueous	Operating since April 2003
Elk Hills	500	San Joaquin Valley	SCR	Aqueous	Operating since July 2003
Blythe Phase I	520	Mojave Desert	SCR	Aqueous	Operating since October 2003
Henrietta Peaker	96	San Joaquin Valley	SCR	Aqueous	Operating since July 2002
Los Esteros	180	Bay Area	SCR	Aqueous	Operating since March 2003
Tracy Peaker	169	San Joaquin Valley	SCR	Aqueous	Operating since June 2003
Pico Power	147	Bay Area	SCR	Aqueous	Under construction
Magnolia	328	South Coast	SCR	Aqueous	Under construction
SMUD Cosumnes	500	Sacramento	SCR	Aqueous	Under construction
Pastoria	750	San Joaquin Valley	SCR	Aqueous	Under construction
Metcalf	600	Bay Area	SCR	Aqueous	Under construction
City of Vernon	134	South Coast	SCR	Aqueous	Under construction
Mountainview	1,056	South Coast	SCR	Aqueous	Re-financing project
Western Midway-Sunset	500	San Joaquin Valley	SCR	Aqueous	On hold
Otay Mesa	510	San Diego	SCONOx or SCR	Aqueous (if SCR)	Construction on hold
Three Mountain	500	Shasta	SCR	Aqueous	On hold
Contra Costa	530	Bay Area	SCR	Aqueous	Construction on hold
Russell City	600	Bay Area	SCR	Aqueous	On hold
Palomar Escondido	546	San Diego	SCR	Aqueous	Financing project
East Altamont	1,100	Bay Area	SCR	Anhydrous	On hold
Inland Empire	670	South Coast	SCR	Aqueous	On hold
San Joaquin Valley Energy Center	1,087	San Joaquin Valley	SCR	Aqueous	On hold

*Does not include emergency peaker projects.

3. Spent Catalyst Waste

Once the activity level of the SCR catalyst has sufficiently diminished, it must be removed and replaced with fresh material. The generator has the option of either disposing the spent catalyst in a landfill or having a third party recycle it. Some catalyst manufacturers offer a disposal service for spent catalyst. Typically, they either reactivate the catalyst for reuse or recycle catalyst components for other uses. Where spent catalyst cannot be reactivated or recycled, it is disposed of in approved landfills.

Typical SCR catalysts are composed of the base metals titanium and vanadium. Although vanadium is not a federal Resource Conservation and Recovery Act (RCRA)[6] hazardous waste constituent, it is on the California list of hazardous waste constituents. Therefore, the generator must assess the vanadium concentration of the spent catalyst and determine whether it fails the California toxicity characteristic (22 California Code of Regulations §66261.24). As a non-RCRA hazardous waste, the spent catalyst would be subject to hazardous waste handling requirements while in California.

[6] RCRA gave U.S. EPA the authority to control hazardous waste from "cradle-to-grave." This includes the generation, transportation, treatment, storage, and disposal of hazardous waste. RCRA also set forth a framework for the management of non-hazardous wastes.

The general handling and disposal requirements for RCRA and non-RCRA wastes are the same while the waste is in the State, but the handling and disposal requirements are different when the waste is taken out-of-state. A registered hazardous waste transporter must haul the waste while in the State, but once out of the State, non-RCRA wastes can be hauled by common carrier. Many states allow non-RCRA waste to be disposed of in non-hazardous landfills or non-hazardous treatment facilities (like recyclers), though some require hazardous wastes to retain the designation of the state of origin.

B. SCONOx Catalytic Absorption System

1. Spent Catalyst Waste

The SCONOx catalyst is a platinum-based substrate with a potassium carbonate coating. Platinum is not listed as a hazardous constituent in either the federal or State list of hazardous waste constituents. Therefore, it would not be regulated as a hazardous waste unless the catalyst carried some other kind of hazardous constituent. As the catalyst contains a precious metal (platinum) component that yields a salvage value, a management program for the catalyst can include the repurchase of the spent catalyst by the manufacturer.

2. Catalyst Regeneration System

As described in Chapter III, the regeneration cycle of the SCONOx catalyst is accomplished by passing a controlled mixture of regeneration gases across the surface of the catalyst in the absence of oxygen. The catalyst is regenerated by introducing natural gas with steam as the carrier gas to a steam reforming catalyst and then to the SCONOx catalyst. The reforming catalyst initiates the conversion of methane in the natural gas to hydrogen, and the conversion is completed over the SCONOx catalyst. Parasitic steam and natural gas quantities for a 500-MW combined-cycle power plant are estimated to have minor overall impacts at three (3) percent and less than one (1) percent of total plant requirements, respectively.

3. Catalyst Washing

The SCOSOx guard bed catalyst is not 100 percent effective in the capture of sulfur compounds, so it is necessary to wash the SCONOx catalyst to remove masking compounds. The washing process uses de-ionized water and potassium carbonate solution to rejuvenate the catalyst to its original level of activity and prevent the need for frequent replacement. The process includes removal of the SCONOx catalyst from the HRSG, washing of the catalyst on-site, and re-installation of the washed catalyst. EmeraChem estimates that the leading layer of SCONOx catalyst will require washing every 8,000 hours of operation, or about once per year for a baseload plant—though experience at the facilities described in Chapter III indicates more frequent washing may be needed to fully optimize NOx reduction. The time interval required to wash the leading layer of SCONOx catalyst is estimated at two to three days. The remaining charge of catalyst is washed every 24,000 hours, or every three years. The waste stream of wash solution is caustic but is not considered a hazardous waste. It can be neutralized and disposed of in a public sewer system. For power plants that do not have ready on site access to a public sewer system, other options exist, including but not limited to, disposal of wastewater to land or surface water if allowed by applicable water quality regulations or transport of the wastewater to an off-site disposal facility or public sewer system that would accept the wastewater.

Alstom Power estimated the annual wash water requirement for a typical 500-MW gas turbine combined-cycle power plant is approximately 12,000 gallons of de-ionized water. This represents less than one (1) percent of a power plant's total water use. For example, factoring the loss of water from evaporation, drift, and blowdown, total makeup water requirements for a typical 500-MW combined-cycle power plant using wet cooling towers is about 250 gallons per MWh, or 3 million gallons per day. For dry cooling, the consumptive water use is estimated to be 50 gallons per MWh, or 600,000 gallons per day.

V. CONTROL COST INFORMATION

Emission levels considered “achieved-in-practice” may be required as BACT in California without consideration of the cost of the control technologies needed to achieve them. However, most air districts in California are required to consider more stringent control technologies than those achieved-in-practice. The more stringent controls must be both technologically feasible *and* cost effective.

The data provided in this chapter is for informational purposes and contains a compilation of capital cost and operation/maintenance (O&M) cost estimates from various sources, including CEC siting case documents, local air district BACT analyses, control system vendors, and environmental consultants. As a general rule, vendors consider certain cost numbers as proprietary, which prevents a detailed and completely equitable cost breakdown analysis. The cost values should only be used for relative comparison purposes. They are not intended to be basis for detailed engineering, marketing, or policy decisions. The respective control technology vendor should be consulted for the most accurate cost information based on site-specific characteristics.

Table V-1 contains averaged cost values for SCONOx and SCR for a 500-MW combined-cycle power plant consisting of two combustion gas turbines and one steam turbine meeting BACT requirements.[7] Where available, the cost of an oxidation catalyst is included with the SCR system for comparable evaluation with SCONOx’s multi-pollutant reduction capabilities. Cost figures show that the SCR/oxidation catalyst package is less than the SCONOx system.

Table V-1. Estimated Average Cost of Post-Combustion Control Technology for a 500-MW Combined-Cycle Gas Turbine Power Plant Meeting BACT

Capital Cost ($)		Annual O&M Cost ($)	
SCR/CO	SCONOx	SCR/CO	SCONOx
6,259,857	20,747,637	1,355,253	3,027,653

Table V-2 contains cost values for SCR at a simple-cycle gas turbine power plant meeting BACT. As mentioned in Chapter III, the SCONOx system is not available for use in simple-cycle configurations because the turbine exhaust temperatures are outside the effective range of the control technology.

[7] The SCONOx system has not been installed at a 500-MW power plant to date. The estimated average cost is based upon a scaling up of the technology.

Table V-2. Selective Catalytic Reduction Cost Estimates for a Simple-Cycle Gas Turbine Power Plant Meeting BACT

	Output (MW)	Turbine Make/Model	Capital Cost for SCR/CO ($)	Annual O&M Cost for SCR/CO ($)
Estimate 1 (April 2001)	49	Pratt & Whitney FT4-C TwinPac	1,391,000 (w/o CO)	427,560
Estimate 2 (December 2003)	48	GE LM6000	1,500,000	-

Table V-3 contains cost values for SCONOx at smaller combined-cycle/cogeneration facilities. The first two estimates represent generic power plants meeting BACT requirements. The last two entries consist of O&M cost data provided by two actual SCONOx installations.

Table V-3. SCONOx Cost Estimates for Combined-Cycle and Cogeneration Gas Turbine Power Plants Under 50 MW

	Output (MW)	Turbine Make/Model	Capital Cost ($)	Annual O&M Cost	Notes
Estimate 1 (February 2004)	5.2	Solar Taurus 60	950,000	Fuel and steam use + approx. $12,000 for catalyst washing	▸ Regeneration fuel is 0.6% of fuel input ▸ Steam use is 1,050 lb/hr
Estimate 2 (February 2004)	14	Solar Titan 130	1,650,000	Fuel and steam use + approx. $25,000 for catalyst washing	▸ Regeneration fuel is 0.6% of fuel input ▸ Steam use is 2,370 lb/hr
Actual Installation (City of Redding)	43	Alstom GTX100	-	$138,000 (approx. $69,000 per wash event at 2 washes per year)	▸ SCONOx catalyst in/out labor, $25,000 ▸ SCONOx catalyst wash, $33,000 ▸ Reformer catalyst in/out labor, $3,000 ▸ Reformer catalyst wash, $8,000
Actual Installation (U.C. San Diego)	26	Solar SoLoNOx Titan 130S	-	$240,0000 (approx. $80,000 per wash event at 3 washes per year)	▸ Potassium carbonate solution, $8,000/turbine ▸ Labor, $25,0000/engine ▸ Cost of replaced grid power, $6,000/day

Table V-4 contains cost estimates for the turbine-integrated NOx control technologies—Xonon and Low Emissions Combustor liner. As described in Chapter III, the Xonon combustor is built into the original turbine equipment. Therefore, the cost includes the complete gas turbine generator package. The Low Emissions Combustor liner is an aftermarket, drop-in device and does not include the cost of the gas turbine generator unit.

Table V-4. Control Cost Estimates for Turbine-Integrated NOx Control Technologies

Control	Turbine Make	Output (MW)	Turbine Model	Installed Cost ($)	Installed Cost Includes	Annual O&M Cost ($)	Annual O&M Cost Includes
Xonon Cool Combustion	Kawasaki	1.4	GPB15X	1.27 million	Complete gas turbine package. Fuel gas compressor, HRSG, etc. not included.	1.1¢/kWhe	Modules, overhauls, scheduled maintenance.
Low Emissions Combustor III	GE 7EA	85.4	PG7121EA	2.0 million	Retrofit dry, lean premix combustion system	No increment over OEM DLN system	
Low Emissions Combustor III	GE 6B	42.1	PG6581B	1.75 million	Retrofit dry, lean premix combustion system	No increment over OEM DLN system	

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APPENDIX A

Table A-1. Emission Controls Required for Combined-Cycle and Cogeneration Power Plant Gas-Fired Turbines

Facility Name	Permitting Agency	Basic Equipment	Method of Control	Permit Status	Emission Limit, per turbine (ppmvd @ 15% O_2 unless otherwise noted)					
					NOx	CO	VOC	PM10	SOx	NH_3
Island End Cogeneration /Cabot Power Corp. (350 MW) Everett, MA	MA Dept. of Envir. Protection	2,493 MMBtu/hr Siemens-Westinghouse 501G gas turbine with HRSG producing 230 MW and steam turbine producing 120 MW	SCR, oxidation catalyst	Permit: MBR-97-COM-014 (App. No.) Issued: 10/9/98 (Proposed Conditional Approval) Status: Construction not started	2.0 (1-hr avg.)	2.0 (1-hr avg.)	2.0 (1-hr avg.)	100% load 32.0 lb/hr; 0.012 lb/MMBtu 75% load 25.8 lb/hr; 0.012 lb/MMBtu	100% load 5.9 lb/hr; 0.0022 lb/MMBtu 75% load 4.7 lb/hr; 0.0022 lb/MMBtu	2 (1-hr avg.)
Limerick Partners LLC (550 MW) 3298 Sanatoga Rd., Limerick Township, Montgomery Co., PA	PA Dept. of Envir. Protection Bureau of Air Quality	(2) GE PG7241FA gas turbines with duct-fired HRSG and steam turbine	DLN + SCR, oxidation catalyst	Permit: PA-46-0203 (Plan Approval for Construction) Issued: 4/9/02 Status: NA	2.0 (1-hr block avg.)	8.1 (1-hr block avg.)	2.4 (1-hr block avg.)	19.75 lb/hr	0.8 (1-hr block avg.); 8.9 lb/hr	10 (1-hr block avg.)
Sithe Mystic Development LLC (1,550 MW) 39 Rover St., Everett, MA	MA Dept. of Envir. Protection	(2) 775 MW power blocks #8 and #9 each consisting of: (2) 2,699 MMBtu/hr Mitsubishi 501G gas turbines each with 253 MMBtu/hr duct-fired HRSG producing 250 MW each and steam turbine producing 275 MW	SCR, oxidation catalyst	Permit: MBR-99-COM-012 (App. No.) Issued: 9/29/99 (Proposed Conditional Approval) Status: Operating	2.0 (1-hr block avg.)	2.0 (1-hr block avg.)	w/ DB 1.7 (1-hr block avg.) w/o DB 1.0 (1-hr block avg.)	32.5 lb/hr; 0.011 lb/MMBtu	8.6 lb/hr; 0.0029 lb/MMBtu	2.0 (1-hr block avg.)[1]

[1] 14-month optimization program. Limit applies first five years. After, limit is 0.0 unless extended by the Agency.

Table A-1. Emission Controls Required for Combined-Cycle and Cogeneration Power Plant Gas-Fired Turbines

Facility Name	Permitting Agency	Basic Equipment	Method of Control	Permit Status	Emission Limit, per turbine (ppmvd @ 15% O_2 unless otherwise noted)					
					NOx	CO	VOC	PM10	SOx	NH_3
Rhode Island State Energy Partners L.P. (535 MW) Intersection of Shun Pike and Simmons Lake Dr., Johnston, RI	RI Dept. of Envir. Mangmnt., Office of Air Resources	(2) 2,009 MMBtu/hr Westinghouse 501F gas turbines with 306 MMBtu/hr duct-fired HRSG producing 186 MW each and steam turbine(s)	DLN + SCR	Permit: RI-PSD-6 Issued: 5/3/00 Status: Under construction, expected to complete late 2002	2.0 (1-hr avg.)	w/ DB 17.8 (1-hr avg.) w/o DB 15.9 (1-hr avg.)	w/ DB 2.9 (1-hr avg.) w/o DB 2.0 (1-hr avg.)	w/ DB 21.0 lb/hr; 0.009 lb/MMBtu w/o DB 18.3 lb/hr; 0.009 lb/MMBtu	w/ DB 11.8 lb/hr; 0.0054 lb/MMBtu w/o DB 10.85 lb/hr; 0.0054 lb/MMBtu	5 (1-hr avg.)
Turlock Irrigation District /Walnut Energy Center (250 MW) Near intersection of W. Main St. and Washington Rd., Turlock, CA	San Joaquin Valley APCD	(2) 1,047 MMBtu/hr GE Frame 7EA gas turbines producing 84 MW each and steam turbine producing 100 MW	DLN + SCR, oxidation catalyst	Permit: N-2246-3-0, N-2246-4-0 Issued: 6/30/03 Status: Expected commercial operation Mar.'06	2.0 (1-hr avg.)[2]	4.0 (3-hr rolling avg.)	1.4 (3-hr rolling avg.)	7.0 lb/hr; 0.0067 lb/MMBtu	0.0010 lb/MMBtu	10 (24-hr rolling avg.)
ANP Blackstone (550 MW) Elm St., Blackstone, MA	MA Dept. of Envir. Protection	(2) ABB GT-24 gas turbines with unfired HRSG producing 180 MW each (210 w/ steam aug.) and steam turbine producing 190 MW (170 MW w/ steam aug.)	SCR, oxidation catalyst	Permit: 118969 (Transmittal No.) Issued: 3/16/01 (Final Approval) Status: Operating since June '01 (Unit 1), July '01 (Unit 2)	2.0 (1-hr block avg.) steam aug. 3.5 (1-hr block avg.)	50% load 20.0 (1-hr block avg.) 75% load 4.0 (1-hr block avg.) 100% load + steam aug. 3.0 (1-hr block avg.)	50% load 2.5 (1-hr block avg.) 75% load 1.4 (1-hr block avg.) 100% load + steam aug. 3.5 (1-hr block avg.)	0.012 lb/MMBtu	0.0023 lb/MMBtu	2.0 (1-hr block avg.)

[2] Allowance for short-term excursions as a result of transient load conditions limited to 10 hours per rolling 12-month period. Maximum 1-hour NOx shall not exceed 30 ppmvd @ 15% O_2.

Table A-1. Emission Controls Required for Combined-Cycle and Cogeneration Power Plant Gas-Fired Turbines

Facility Name	Permitting Agency	Basic Equipment	Method of Control	Permit Status	Emission Limit, per turbine (ppmvd @ 15% O_2 unless otherwise noted)					
					NOx	CO	VOC	PM10	SOx	NH_3
ANP Bellingham Energy Company (550 MW) Bellingham, MA	MA Dept. of Envir. Protection	(2) 1,815 MMBtu/hr ABB GT-24 gas turbines with unfired HRSG producing 180 MW each (210 MW w/ steam aug.) and (2) steam turbines producing 190 MW (170 MW w/ steam aug.)	SCR, oxidation catalyst	Permit: 118970 (Transmittal No.) Issued: 4/10/02 (Final Approval) Status: Operating	2.0 (1-hr block avg.) <u>steam aug.</u> 3.5 (1-hr block avg.)	<u>50% load</u> 20.0 (1-hr block avg.) <u>75% load</u> 4.0 (1-hr block avg.) <u>100% load + steam aug.</u> 3.0 (1-hr block avg.)	<u>50% load</u> 2.5 (1-hr block avg.) <u>75% load</u> 1.4 (1-hr block avg.) <u>100% load + steam aug.</u> 3.5 (1-hr block avg.)	0.012 lb/MMBtu	0.002 lb/MMBtu	2.0 (1-hr block avg.)
AERA/Western Midway Sunset (510 MW) Crocker Springs Rd., Fellows, CA	San Joaquin Valley APCD	(2) GE Frame 7F or (2) Westinghouse 501F gas turbines with HRSG producing 170 MW each and steam turbine producing 170 MW	DLN + SCR, oxidation catalyst	Permit: S-1135-313-0, S-1135-4-0 Issued: Status: Construction on hold	<u>w/ GE</u> 2.0 (1-hr avg.) <u>w/ Westng.</u> 2.5 (1-hr avg.)	6 (1-hr avg.)	<u>w/ GE</u> 1.4 (3-hr avg.) <u>w/ Westng.</u> 1.5 (3-hr avg.)	9.4 lb/hr	<u>w/ GE</u> 3.8 lb/hr <u>w/ Westng.</u> 3.9 lb/hr	10 (24-hr avg.)
Lake Road Generating Company (840 MW) Lake Rd., Killingly, CT	CT Dept. of Envir. Protection	(3) 2,181 MMBtu/hr ABB GT-24 gas turbines and steam turbines	DLN + SCR, oxidation catalyst	Permit: 0068 Issued: 5/21/99 (Draft Permit) Status: Operating	2.0 (3-hr block avg.)	<u>100% load</u> 3.0 (1-hr block avg.) <u>75% load</u> 4.0 (1-hr block avg.) <u>50% load</u> 20.0 (1-hr block avg.)	0.0017 lb/MMBtu; 3.08 lb/hr	21.8 lb/hr; 0.0122 lb/MMBtu	4.73 lb/hr; 0.0026 lb/MMBtu	10.0 (3-hr block avg.)[3]

[3] After first year of operation, data to be reviewed and limit revised to reflect actual emissions.

Table A-1. Emission Controls Required for Combined-Cycle and Cogeneration Power Plant Gas-Fired Turbines

Facility Name	Permitting Agency	Basic Equipment	Method of Control	Permit Status	Emission Limit, per turbine (ppmvd @ 15% O_2 unless otherwise noted)					
					NOx	CO	VOC	PM10	SOx	NH_3
Milford Power 1 Shelland St., Milford, CT	CT Dept. of Envir. Protection	(2) 1,965 MMBtu/hr ABB GT-24 gas turbines with HRSG and steam turbine	DLN + SCR, oxidation catalyst	Permit: 0068 Issued: 4/16/99 Status: Construction completed. Unit 1 tested on 12/30/03. Unit 2 not tested yet.	2.0 (3-hr block avg.)	<u>100% load</u> 13.0 lb/hr <u>50-99% load</u> 52.0 lb/hr	<u>100% load</u> @≥81°F 7.5 lb/hr, @71-80°F 3.7 lb/hr, @61-70°F 3.2 lb/hr, @≤60°F 3.0 lb/hr <u>75-99% load</u> 2.2 lb/hr <u>50-74% load</u> 3.0 lb/hr	19.9 lb/hr; 0.011 lb/MMBtu	4.4 lb/hr; 0.0022 lb/MMBtu	10 (3-hr block avg.)[4]
Redding Power Unit 5 (56 MW) 17120 Clear Creek Rd., Redding, CA	Shasta Co. AQMD	407 MMBtu/hr Alstom Power GTX 100 gas turbine with HRSG producing 43 MW and steam turbine producing 13 MW	SCONOx + SCOSOx	Permit: 00-PO-39 Issued: 3/30/01 Status: Operating since June '02	2.5 (1-hr rolling avg.)[5]	6.0 (1-hr rolling avg.)	1.4 (1-hr rolling avg.)	0.0012 gr/dscf @ 3% CO_2 (1-hr avg.)	0.2 (1-hr rolling avg.)	NA
Calpine Ontelaunee Energy Center (544 MW) Ontelaunee Township, Berks Co., PA	PA Dept. of Envir. Protection Bureau of Air Quality	(2) Siemens-Westinghouse 501F gas turbines with HRSG producing 182 MW each and steam turbine producing 180 MW	DLN + SCR	Permit: 06-5100 (Plan Approval for Construction) Issued: 10/10/00 Status: NA	2.5 (1-hr avg.), 2.0 (3-hr avg.)	10.0 (1-hr avg.); 0.0228 lb/MMBtu* *Install oxidation catalyst if fail to meet limits	1.8 (1-hr avg.); 0.0023 lb/MMBtu* *Install oxidation catalyst if fail to meet limits	0.0061 lb/MMBtu	0.0056 lb/MMBtu	10

[4] After first year of operation, data to be reviewed and limit revised to reflect actual emissions.
[5] Demonstration NOx limit of 2.0 (1-hr rolling average) to be evaluated over a three-year period.

Table A-1. Emission Controls Required for Combined-Cycle and Cogeneration Power Plant Gas-Fired Turbines

Facility Name	Permitting Agency	Basic Equipment	Method of Control	Permit Status	Emission Limit, per turbine (ppmvd @ 15% O_2 unless otherwise noted)					
					NOx	CO	VOC	PM10	SOx	NH_3
Cogen Technologies Linden Venture L.P. (180.6 MW) within Tosco Bayway Refinery, Railroad and Chemico Ave., Linden, NJ	NJ Dept. of Envir. Protection	1,954.6 MMBtu/hr GE PG7241 (FA) gas turbine with unfired HRSG producing 180.6 MW	DLN + SCR, oxidation catalyst	Permit: 000002, Facility ID 40955 Issued: 5/9/01 Status: NA	2.5 (1-hr avg.)	2 (1-hr avg.)	1.2 (1-hr avg.)	51.8 (1-hr avg.)	1.44 (1-hr avg.)	10 (3-hr rolling avg. based on a 1-hr block avg.)
University of California San Diego (26 MW) 9500 Gilman Dr., San Diego, CA	San Diego Co. APCD	(2) 148.64 MMBtu/hr Solar SoLoNOx Titan 130S gas turbines producing 12.894 MW each (aka Unit 100 and Unit 200)	SCONOx + SCOSOx	Permit: 974480, 974481 Issued: 4/16/02 Status: Operating since July '01	2.5 (3-hr rolling avg.)	5.0	-	-	-	NA
Wyeth Bio Pharma Unit 1 (6.2 MW) One Burtt Rd., Andover, MA	MA Dept. of Envir. Protection	76 MMBtu/hr Solar Taurus Model 60 gas turbine with 17.8 MMBtu/hr duct-fired HRSG producing 6.2 MW	DLN + SCONOx + SCOSOx	Permit: MBR-98-COM-001 (Final Approval) Issued: 9/4/02 Status: Operating since July 1999	nat. gas 2.5 (1-hr avg.) oil 15.0 (1-hr avg.)	5.0 (1-hr avg.)	-	0.010 lb/MMBtu	Fuel oil sulfur content ≤0.0015% S by weight	NA
Wyeth Bio Pharma Unit 2 (5.9 MW) One Burtt Rd., Andover, MA	MA Dept. of Envir. Protection	68.1 MMBtu/hr Solar Taurus Model 60 gas turbine with 18.8 MMBtu/hr duct-fired HRSG producing 5.9 MW	DLN + SCONOx + SCOSOx[6]	Permit: MBR-01-COM-053 (Conditional Approval) Issued: 2/28/02 Status: Operating	nat. gas 2.5 (1-hr avg.) oil 15.0 (1-hr avg.)	2.0 (1-hr avg.)	0.028 lb/MMBtu	nat. gas 0.020 lb/MMBtu oil 0.0360 lb/MMBtu	Fuel oil sulfur content ≤0.005% S by weight	NA

[6] Approval includes an 18-month optimization period to consistently maintain the NOx limits specified, with a goal of attaining 9 ppmvd NOx and 2.0 ppmvd CO at 15% O_2 while combusting fuel oil. If permit limits cannot be met, the applicant may replace with an SCR system and oxidation catalyst meeting: 2.5 (gas) and 9.0 (oil) ppmvd NOx; 2.0 ppmvd CO; 3.0 ppmvd NH_3 with a goal of 2.0 ppmvd; all at 15% O_2.

Table A-2. Emission Controls Required for Simple-Cycle Power Plant Gas-Fired Turbines

Facility Name	Permitting Agency	Basic Equipment	Method of Control	Permit Status	Emission Limit, per turbine (ppmvd @ 15% O_2 unless otherwise noted)					
					NOx	CO	VOC	PM10	SOx	NH_3
Lowell Power LLC (96 MW) 121 Maple St., Lowell, MA	MA Dept. of Envir. Protection	(2) 456.32 MMBtu/hr GE LM6000 gas turbines producing 48 MW each (aka Units 2 and 3)	Water injection + SCR, oxidation catalyst	Permit: MBR-00-COM-039 (App. No.) Issued: 6/6/01 (Proposed Conditional Approval) Status: Construction not started	2.0 (1-hr block avg.)	≥42°F 5.0 (1-hr block avg.) <42°F 10.0 (1-hr block avg.)	3.0 (1-hr block avg.)	3.0 lb/hr; 0.012 lb/MMBtu	1.0 lb/hr; 0.0029 lb/MMBtu	2.0 (1-hr block avg.)
Wallingford Energy (225 MW) 195 East St., Wallingford, CT	CT Dept. of Envir. Protection	(5) 461.2 MMBtu/hr GE LM6000 gas turbines producing 45 MW each	Water injection + SCR, oxidation catalyst	Permit: 189-114-0194 (Unit 1), '-0195 (Unit 2), '-0196 (Unit 3), '-0197 (Unit 4), '-0198 (Unit 5) Issued: 2/2/02 Status: Operating	2.5 (1-hr block avg.)	0.0364 lb/MMBtu	0.0107 lb/MMBtu	12.1 lb/hr; 0.026 lb/MMBtu	1.26 lb/hr; 0.0027 lb/MMBtu	6 (3-hr block avg.)
New York Power Authority /Hell Gate (94 MW) Bronx, NY	NY Dept. of Envir. Quality	(2) GE LM6000 Sprint gas turbines producing 47 MW each	Water injection + SCR, oxidation catalyst	Permit: 2-6007-00724/00001 (Air State Facility No.) Issued: Status: Operating	2.5 (1-hr avg.)	0.013 lb/MMBtu	1.2 lb/hr	3.0 lb/hr	-	10.0
Calpine /Creed Energy Center (49.9 MW) 6150 Creed Rd., Suisun City, CA	Bay Area AQMD	500 MMBtu/hr GE LM6000 PC Sprint gas turbine producing 49.9 MW	Water injection + SCR, oxidation catalyst	Permit: 4926 (ATC) Issued: 9/18/02 Status: Operating since Jan.'03	2.5 (3-hr rolling avg.)	6 (1-hr rolling avg.)	2 (1-hr rolling avg.)	3.0 lb/hr	1.38 lb/hr	10 (1-hr rolling avg.)
Calpine /Lambie Energy Center (49.9 MW) 5975 Lambie Rd., Suisun City, CA	Bay Area AQMD	500 MMBtu/hr GE LM6000 PC Sprint gas turbine producing 49.9 MW	Water injection + SCR, oxidation catalyst	Permit: 4881 (ATC) Issued: 9/11/02 Status: Operating since Jan.'03	2.5 (3-hr rolling avg.)	6 (1-hr rolling avg.)	2 (1-hr rolling avg.)	3.0 lb/hr	1.38 lb/hr	10 (1-hr rolling avg.)
Calpine /Goose Haven Energy Center (49.9 MW) 3853 Goose Haven Rd., Suisun City, CA	Bay Area AQMD	500 MMBtu/hr GE LM6000 PC Sprint gas turbine producing 49.9 MW	Water injection + SCR, oxidation catalyst	Permit: 4925 (ATC) Issued: 8/14/02 Status: Operating since Jan.'03	2.5 (3-hr rolling avg.)	6 (1-hr rolling avg.)	2 (1-hr rolling avg.)	3.0 lb/hr	1.38 lb/hr	10 (1-hr rolling avg.)

Table A-2. Emission Controls Required for Simple-Cycle Power Plant Gas-Fired Turbines

Facility Name	Permitting Agency	Basic Equipment	Method of Control	Permit Status	Emission Limit, per turbine (ppmvd @ 15% O_2 unless otherwise noted)					
					NOx	CO	VOC	PM10	SOx	NH_3
Modesto Irrigation District (95 MW) S. Stockton Ave. and Doak Blvd., Ripon, CA	San Joaquin Valley APCD	(2) 500 MMBtu/hr GE LM6000 Sprint gas turbines producing 47.5 MW each	Water injection + SCR, oxidation catalyst	Permit: N-4940-1-0, N-4940-2-0 (ATC) Issued: 3/8/04 Status: Construction not started	2.5 (3-hr rolling avg.)	6.0 (3-hr rolling avg.)	2.0 (3-hr rolling avg.)	3.00 lb/hr	0.51 lb/hr	10.0 (24-hr rolling avg.)
CalPeak Power Midway /Lodi Electric Energy Facility (49 MW) 1215 Thurman Rd., Lodi, CA	San Joaquin Valley APCD	464.7 MMBtu/hr Pratt & Whitney FT8-2 "Twin Pac" gas turbines with common generator and exhaust stack producing 49 MW	DLN + SCR, oxidation catalyst[7]	Permit: N-4834-1-0 Issued: NA Status: NA	3.0 (3-hr rolling avg.)	5 (3-hr rolling avg.)	2.0 (3-hr rolling avg.)	144 lb/day	32.4 lb/day	10.0 (24-hr rolling avg.)
Lodi Energy Center LLC (49.6 MW) 610 S. Guild Ave., Lodi, CA	San Joaquin Valley APCD	GE LM6000 Sprint gas turbine producing 49.6 MW	Water injection + SCR, oxidation catalyst	Permit: N-4857-1-0 (ATC) Issued: 6/18/03 Status: Construction not started	3.0 (3-hr rolling avg.)	6.0 (3-hr rolling avg.)	2.0 (3-hr rolling avg.)	3.00 lb/hr	1.43 lb/hr	10.0 (24-hr rolling avg.)
Herndon Energy Center (49.6 MW) Fresno, CA	San Joaquin Valley APCD	500 MMBtu/hr GE LM6000 Sprint gas turbine producing 49.6 MW	Water injection + SCR, oxidation catalyst	Permit: N-4030-1-0 (ATC) Issued: 7/8/02 Status:	3.0 (3-hr rolling avg.)	6.0 (3-hr rolling avg.)	2.0 (3-hr rolling avg.)	3.00 lb/hr	0.36 lb/hr	10 (24-hr rolling avg.)
Northern California Power (49 MW) 12751 Thornton Rd., Lodi, CA	San Joaquin Valley APCD	417 MMBtu/hr GE LM5000 gas turbine producing 49 MW	Water injection + SCR, oxidation catalyst	Permit: N-2697-1-1 Issued: NA Status: Operating	3.0 (3-hr rolling avg.)	200 (3-hr rolling avg.)	142 lb/day	48 lb/day	-	25
CalPeak Power Border LLC (49.5 MW) Harvest Rd. and Hwy 905, San Diego, CA	San Diego Co. APCD	500 MMBtu/hr Pratt & Whitney FT8 "Twin Pac" gas turbines with common generator and exhaust producing 49.5 MW	DLN + SCR, oxidation catalyst	Permit: 976502 (ATC) Issued: NA Status: Operating since 10/26/01	3 (3-hr rolling avg.); 2.5 (24-hr rolling avg.)	50 (3-hr rolling avg.)	2	-	-	10

[7] Turbine exhaust temperature (~950°F) is too high for a standard SCR system catalyst. Applicant proposes to introduce fresh air in exhaust upstream of SCR system to reduce exhaust to ~730°F.

Table A-2. Emission Controls Required for Simple-Cycle Power Plant Gas-Fired Turbines

Facility Name	Permitting Agency	Basic Equipment	Method of Control	Permit Status	Emission Limit, per turbine (ppmvd @ 15% O_2 unless otherwise noted)					
					NOx	CO	VOC	PM10	SOx	NH_3
CalPeak Power Panoche (49.4 MW) 43699 W. Panoche Rd., Firebaugh, CA	San Joaquin Valley APCD	Pratt & Whitney FT8 "Twin Pac" gas turbines with common generator and exhaust producing 49.4 MW	DLN + SCR, oxidation catalyst	Permit: C-3811-1-0, C-3811-2-0 (ATC) Issued: 4/26/01 Status: Operating since Dec.'01	3.4 (3-hr rolling avg.)	6.8 (3-hr rolling avg.)	2.0 (3-hr rolling avg.)	1.62 lb/hr (3-hr rolling avg.)	0.71 lb/hr (3-hr rolling avg.)	10 (3-hr rolling avg.)
West Springfield Redevelopment Project (84 MW) existing West Springfield Station, West Springfield, MA	MA Dept. of Envir. Protection	(2) 462.6 MMBtu/hr GE LM6000 gas turbines producing 42 MW each	Water injection + SCR, oxidation catalyst	Permit: 1-B00-038 (App. No.) Issued: 4/11/01 (Conditional Approval), 6/23/03 (Final Approval) Status: Operating	3.5 (1-hr block avg.)[8]	<u>≥42°F</u> 5.0 (1-hr block avg.) <u><42°F</u> 10.0 (1-hr block avg.)	3.0 (1-hr block avg.)	3.0 lb/hr; 0.008 lb/MMBtu	1.0 lb/hr; 0.0029 lb/MMBtu	7.0 (1-hr block avg.)
Wellhead Power Gates LLC (45.4 MW) Huron, CA	San Joaquin Valley APCD	436 MMBtu/hr GE LM6000 gas turbine producing 45.4 MW	Water or steam injection + SCR, oxidation catalyst	Permit: C-3843-1-0 (ATC) Issued: 8/30/01 Status: Operating	3.5 (3-hr rolling avg.)	6.0 (1-hr rolling avg.)	2.0 (1-hr rolling avg.)	2.88 lb/hr	1.26 lb/hr	10 (1-hr rolling avg.)
E.I. Colton LLC (48 MW) 2040 Aqua Mansa Rd., Colton, CA	South Coast AQMD	456.5 MMBtu/hr GE LM6000 Sprint gas turbine producing 48 MW	Water injection + SCR, oxidation catalyst	Permit: 406065 Issued: 11/26/02 Status: NA	3.5 (3-hr rolling avg.)	6 (3-hr rolling avg.)	2 (3-hr rolling avg.)	3.33 lb/hr	0.162 lb/hr	5 (3-hr rolling avg.)
Gilroy Energy Center Phase I (135 MW) at the Calpine Gilroy Power Plant, Gilroy, CA	Bay Area AQMD	(3) 467.6 MMBtu/hr GE LM6000PC gas turbines producing 45 MW each	Water injection or DLN + SCR, oxidation catalyst	Permit: NA Issued: 5/21/01 Status: Operating	5 (1-hr rolling avg.)	6 (3-hr rolling avg.)	2 (3-hr rolling avg.)	2.5 lb/hr	0.33 lb/hr	10 (3-hr rolling avg.)
Wildflower Energy /Indigo (135 MW) 19th Ave., Palm Springs, CA	South Coast AQMD	(3) 450 MMBtu/hr GE LM6000 Enhanced Sprint gas turbines producing 45 MW each	Steam or water injection + SCR, oxidation catalyst	Permit: 127299 (ATC) Issued: 7/13/01 Status: Operating since 7/26/01	5 (1-hr rolling avg.)	6 (1-hr rolling avg.)	2	6.8 lb/MMscf	0.32 lb/MMscf	5 (1-hr rolling avg.)

[8] Conditional Approval stated that system was to be designed to achieve 2 ppm limits for NOx and ammonia, but that upon completion of an optimization program, new limits may need to be established if consistent compliance cannot be maintained. The levels listed herein are the final established emission limits for NOx and ammonia.

Table A-2. Emission Controls Required for Simple-Cycle Power Plant Gas-Fired Turbines

Facility Name	Permitting Agency	Basic Equipment	Method of Control	Permit Status	Emission Limit, per turbine (ppmvd @ 15% O_2 unless otherwise noted)					
					NOx	CO	VOC	PM10	SOx	NH_3
Sacramento Municipal Utility District (77 MW) McClellan Air Force Base, Sacramento, CA	Sac Metro AQMD	927 MMBtu/hr GE Frame 7E PG7931 gas turbine producing 77 MW	Water injection + SCR	Permit: 14332, 14333 (ATC) Issued: 3/24/00 Status: Operating	5 (3-hr rolling avg.)	46.98 lb/hr (3-hr avg.)	2.36 lb/hr (3-hr avg.)	7.00 lb/hr (3-hr avg.)	0.56 lb/hr (3-hr avg.)	10 (3-hr avg.)
GWF Energy LLC /Tracy Peaker Power Plant (169 MW) Tracy, CA	San Joaquin Valley APCD	(2) 990.6 MMBtu/hr GE PG7121 EA gas turbines producing 84.5 MW each	DLN + SCR, oxidation catalyst	Permit: N-4597-1-0, N-4597-2-0 Issued: 10/5/01 (ATC) Status: Operating since 6/1/03	5.0 (3-hr rolling avg.)	6.0 (3-hr rolling avg.)	2.0 (3-hr rolling avg.)	10.3 lb/hr	0.70 lb/hr	10 (24-hr rolling avg.)
PG&E Dispersed Generating Company /Chula Vista (44 MW) 3497 Main St., Chula Vista, CA	San Diego Co. APCD	688 MMBtu/hr Pratt & Whitney FT4/GG4 "Twin Pac" gas turbines producing 44 MW	DLN + SCR, oxidation catalyst	Permit: 976039 (ATC) Issued: 7/5/01 Status: Operating	9 (1-hr avg.); 5 (3-hr rolling avg.)	50 (1-hr avg.)	2	-	-	10
Wildflower Energy /Larkspur (135 MW) Harvest Rd., Otay Mesa area, San Diego, CA	San Diego Co. APCD	(2) 395 MMBtu/hr GE LM6000 PC Sprint gas turbines producing 45 MW each	Water injection + SCR, oxidation catalyst	Permit: 976094 (ATC) Issued: 4/24/01 Status: Operating since 7/16/01	9 (1-hr avg.); 5 (3-hr rolling avg.)	50 (1-hr avg.)	2	-	-	10
Dynegy /Bluegrass Generation Company LLC (624 MW) 3200 W. Hwy 146, LaGrange, KY	KY Dept. of Air Quality	(3) 2,076 MMBtu/hr Siemens-Westinghouse 501FD gas turbines producing 208 MW each	DLN + SCR* *SCR install on two units only)[9]	Permit: V-00-052 (Title V) Issued: 6/5/01 Status: Operating since 2nd quarter '02	111 (3-hr rolling avg.)* *Target 5-6 ppm w/ SCR	50 (3-hr avg.0	-	-	-	-

[9] Permittee has the option of installing high temperature SCR. Targeting NOx emissions out the turbine are 15 ppmvd @ 15% O_2.

APPENDIX B

Table B-1. Emission Source Test Results for Combined-Cycle and Cogeneration Power Plant Gas Turbines

Facility Name	Permitting Agency	Basic Equipment	Method of Control	Date Tested	Average Measured Emissions, per turbine (ppmvd @ 15% O_2 unless otherwise noted)				
					NOx	CO	VOC	PM10 (lb/hr)	NH_3
ANP Blackstone (550 MW) Elm St., Blackstone, MA	MA Dept. of Envir. Protection	(2) ABB GT-24 gas turbines with unfired HRSG producing 180 MW each (210 MW w/ steam aug.) and steam turbine producing 190 MW (170 MW w/ steam aug.)	SCR, oxidation catalyst	**CTG1** 6/5-7/2001 82% load	1.5	<0.1	0.4	0.767	0.07
				75% load	1.6	<0.1	0.2	0.433	0.06
				50% load	1.4	0.5	0.2	0.800	0.08
				CTG2 7/11-12/2001 82% load	1.6	<0.1	0.4	2.83	<0.02
				75% load	1.5	<0.1	0.4	3.30	0.02
				50% load	1.7	0.8	0.4	19.2	0.2
				CTG2 12/5-6/2001 82% load	1.4	<0.1	0.1	-	0.05
				50% load (retest for PM10)	-	-	-	2.50 (front half only)	-
				CTG1 2/11-12/2002 87% load	1.6	0.3	0.1	-	0.1
				5/15/2002 87% load	1.6 (CTG1) 1.6 (CTG2)	0.3 (CTG1) 0.0 (CTG2)	0.1 (CTG1) 0.1 (CTG2)	-	0.1 (CTG1) 0.1 (CTG2)
Elk Hills Power LLC (500 MW) 4026 Skyline Rd., Tupman, CA	San Joaquin Valley APCD			5/20/2003 100% load w/o DB	2.29 (CTG1) 2.40 (CTG2)	0.47 (CTG1) 0.05 (CTG2)	<0.80 (CTG1) <0.80 (CTG2)	9.56 (CTG1) 11.45 (CTG2)	0.07 (CTG1) 0.10 (CTG2)
				5/21/2003 100% load w/ DB	1.56 (CTG1) 1.89 (CTG2)	0.57 (CTG1) 0.00 (CTG2)	<0.65 (CTG1) <0.67 (CTG2)	8.22 (CTG1) 10.99 (CTG2)	0.28 (CTG1) 0.58 (CTG2)
High Desert Power Project LLC (830 MW) Victorville, CA	Mojave Desert AQMD	(3) Siemens-Westinghouse 501F gas turbines with HRSG producing 190 MW each and steam turbine producing 330 MW		4/5/2003	2.39 (CTG1) 2.99 (CTG3)	0.17 (CTG1) 0.25 (CTG3)	0.38 (CTG1) 1.06 (CTG3)	16.50 (CTG1) 16.43 (CTG3)	5.38 (CTG1) 0.95 (CTG3)
				CTG2 4/7/2003	2.38	0.0629	0.57	9.15	6.54
				CTG3 4/30/2003 (retest)	2.41	-	-	-	-
Los Medanos Energy Center (555 MW) Pittsburg, CA	Bay Area AQMD	(2) 1,929 MMBtu/hr GE Frame 7FA PG7241 gas turbines with 333 MMBtu/hr duct-fired HRSG producing 170 MW each and (2) steam turbines producing 90 MW each	DLN + SCR, oxidation catalyst	7/19-8/24/2001 full load w/ DB	2.115 (CTG1) 1.648 (CTG2)	0.046 (CTG1) 0.043 (CTG2)	10.12 (CTG1) 1.714 (CTG2)	3.53; 0.00232 lb/MMBtu (CTG1) 2.31; 0.00150 lb/MMBtu (CTG2)	0.09 (CTG1) 0.13 (CTG2)
				60% load	-	0.045 (CTG1) 0.042 (CTG2)	2.64 (CTG1) 0.74 (CTG2)	-	-

Table B-1. Emission Source Test Results for Combined-Cycle and Cogeneration Power Plant Gas Turbines

Facility Name	Permitting Agency	Basic Equipment	Method of Control	Date Tested	Average Measured Emissions, per turbine (ppmvd @ 15% O_2 unless otherwise noted)				
					NOx	CO	VOC	PM10 (lb/hr)	NH_3
University of California San Diego (26 MW) 9500 Gilman Dr., San Diego, CA	San Diego Co. APCD	(2) 148.64 MMBtu/hr Solar SoLoNOx Titan 130S gas turbines producing 12.894 MW each (aka Unit 100 and Unit 200)	SCONOx + SCOSOx	**CTG1** 12/19-20/2001	0.68	<0.04	-	-	NA
				CTG2 12/23/2001	1.01	<0.04	-	-	NA
Wyeth Bio Pharma #1 /Genetics Institute (5 MW) Andover, MA	MA Dept. of Envir. Protection	Solar Taurus 60 gas turbine with duct-fired HRSG producing 5 MW	SCONOx + SCOSOx	2/14-17/2000					
Sutter Power Plant (540 MW) 5029 S. Township Rd., Yuba City, CA	Feather River AQMD	(2) 1,900 MMBtu/hr Westinghouse 501F gas turbines with 170 MMBtu/hr duct-fired HRSG producing 170 MW each and steam turbine producing 160 MW	DLN + SCR, oxidation catalyst	6/25-29/2001 full load w/ DB	2.36 (CTG1) 2.20 (CTG2)	0.12 (CTG1) 0.04 (CTG2)	1.51 (CTG1) 1.23 (CTG2)	2.661 (CTG1) 2.242 (CTG2)	7.93 (CTG1) 12.77 (CTG2)
				90% load w/o DB	2.447 (CTG2)	0.343 (CTG2)	4.66 (CTG2)	-	-
				80% load w/o DB	2.233 (CTG2)	0.143 (CTG2)	2.74 (CTG2)	-	-
				70% load w/o DB	2.228 (CTG2)	0.125 (CTG2)	1.81 (CTG2)	-	-
				8/30-31/2001 full load w/ DB (retest for VOC and NH_3)	-	-	0.44 (CTG1) 0.32 (CTG2)	-	<0.05 (CTG1) 7.92 (CTG2)
				10/15-16/2001 100% load w/o DB (retest for VOC)	-	-	0.21 (CTG1) 0.14 (CTG2)	-	-
				90% load w/o DB	-	-	0.19 (CTG1) 0.55 (CTG2)	-	-
				80% load w/o DB	-	-	0.21 (CTG1) 0.26 (CTG2)	-	-
				70% load w/o DB	-	-	0.18 (CTG1) 0.25 (CTG2)		

Table B-1. Emission Source Test Results for Combined-Cycle and Cogeneration Power Plant Gas Turbines

Facility Name	Permitting Agency	Basic Equipment	Method of Control	Date Tested	Average Measured Emissions, per turbine (ppmvd @ 15% O_2 unless otherwise noted)				
					NOx	CO	VOC	PM10 (lb/hr)	NH_3
Mirant Kendall LLC (170 MW) existing Mirant Kendall site, Cambridge, MA	MA Dept. of Envir. Protection	1,766 MMBtu/hr GE 7241 FA gas turbine with 350 MMBtu/hr duct-fired HRSG producing 170 MW with steam routed to (3) existing steam turbines producing 64 MW	DLN + SCR, oxidation catalyst	Date Unknown 100% load w/ DB	1.9	0.0	0.0	2.51; 0.0023 lb/MMBtu	0.2
				100% load	2.0	0.0	0.0	-	0.1
				75% load	1.9	0.0	0.0	-	0.1
				50% load	1.9	0.0	0.0	-	0.1
Mystic Station (1,550 MW)	MA Dept. of Envir. Protection	(4) Mitsubishi 501G gas turbines with HRSG producing 250 MW each and (2) steam turbines (aka Units 81, 82, 93, 94)	DLN + SCR. oxidation catalyst	Date Unknown 100% load w/ DB	1.9 (CTG81) 1.6 (CTG82) 1.5 (CTG93) 1.7 (CTG94)	0.0 (CTG81) 0.0 (CTG82) 0.0 (CTG93) 0.0 (CTG94)	0.3 (CTG81) 0.5 (CTG82) 0.3 (CTG93) 0.2 (CTG94)	32.1; 0.010 lb/MMBtu (CTG81) 16.8; 0.005 lb/MMBtu (CTG82) 22.4; 0.007 lb/MMBtu (CTG93) 14.5; 0.005 lb/MMBtu (CTG94)	0.6 (CTG81) <0.5 (CTG82) 0.8 (CTG93) 0.3 (CTG94)
				100% load	1.6 (CTG81) 1.2 (CTG82) 1.6 (CTG93) 1.7 (CTG94)	0.0 (CTG81) 0.0 (CTG82) 0.0 (CTG93) 0.0 (CTG94)	0.2 (CTG81) 0.7 (CTG82) 0.3 (CTG93) 0.0 (CTG94)	- - - -	0.6 (CTG81) 0.2 (CTG82) 0.6 (CTG93) 0.5 (CTG94)
				87.5% load	1.7 (CTG81) 1.6 (CTG82) 1.6 (CTG93) 1.7 (CTG94)	0.0 (CTG81) 0.0 (CTG82) 0.0 (CTG93) 0.0 (CTG94)	0.2 (CTG81) 0.2 (CTG82) 0.1 (CTG93) 0.1 (CTG94)	- - - -	0.5 (CTG81) <0.3 (CTG82) 0.6 (CTG93) 0.4 (CTG94)
				75% load	1.6 (CTG81) 1.3 (CTG82) 1.4 (CTG93) 1.6 (CTG94)	0.2 (CTG81) 0.2 (CTG82) 0.0 (CTG93) 0.0 (CTG94)	0.0 (CTG81) 0.5 (CTG82) 0.1 (CTG93) 0.1 (CTG94)	- - - -	0.7 (CTG81) 0.3 (CTG82) 0.6 (CTG93) 0.2 (CTG94)

Table B-1. Emission Source Test Results for Combined-Cycle and Cogeneration Power Plant Gas Turbines

Facility Name	Permitting Agency	Basic Equipment	Method of Control	Date Tested	Average Measured Emissions, per turbine (ppmvd @ 15% O_2 unless otherwise noted)				
					NOx	CO	VOC	PM10 (lb/hr)	NH_3
Lake Road Generating Company (840 MW) Lake R., Killingly, CT	CT Dept. of Envir. Protection	(3) 2,181 MMBtu/hr ABB GT-24 gas turbines and steam turbines	DLN + SCR, oxidation catalyst	1/24/2002 >90% load	1.3 (CTG1) 0.8 (CTG2)	<0.4 (CTG1) <0.4 (CTG2)	0.85 (CTG1) <0.4 (CTG2)	20.39; 0.0046 lb/MMBtu (CTG1) <6.65; <0.0038 lb/MMBtu (CTG2)	0.21 (CTG1)
				CTG2 1/25/2002 75% load	0.7	<0.4	<0.4	-	-
				60% load	0.7	1.3	<0.4	-	-
				50% load	1.1	4.7	<0.4	-	-
				CTG3 4/23/2002 >90% load	1.2	<0.4	<0.4	<5.36; <0.0029 lb/MMBtu	0.16
				CTG2 4/24/2002 75% load	1.1	<0.4	<0.4	-	-
				60% load	1.3	1.4	<0.4	-	-
				50% load	1.6	3.1	0.5	-	-

Table B-2. Emission Source Test Results for Simple-Cycle Power Plant Gas Turbines

Facility Name	Permitting Agency	Basic Equipment	Method of Control	Date Tested	Average Measured Emissions, per turbine (ppmvd @ 15% O_2 unless otherwise noted)				
					NOx	CO	VOC	PM10 (lb/hr)	NH_3
New York Power Authority /Hell Gate (94 MW) Bronx, NY	NY Dept. of Envir. Quality	(2) GE LM6000 Sprint gas turbines producing 47 MW each	Water injection + SCR, oxidation catalyst	10/3-4/2001 100% load	2.2 (CTG1) 2.1 (CTG2)	0.1 (CTG1) 0.1 (CTG2)	-	-	9.6 (CTG1) 13.5 (CTG2)
				90% load	2.1 (CTG1) 1.9 (CTG2)	0.1 (CTG1) 0.0 (CTG2)	-	-	-
				80% load	2.0 (CTG1) 1.7 (CTG2)	0.1 (CTG1) 0.0 (CTG2)	-	-	-
				65% load	2.0 (CTG1) 2.0 (CTG2)	0.1 (CTG1) 0.0 (CTG2)	-	-	-
				11/27/2001 (retest for NH_3)	2.3 (CTG2)	0.2 (CTG2)	-	-	3.4 (CTG2)
Calpine /Lambie Energy Center (49.9 MW) 5975 Lambie Rd., Suisun City, CA	Bay Area AQMD	500 MMBtu/hr GE LM6000 PC Sprint gas turbine producing 49.9 MW	Water injection + SCR, oxidation catalyst	1/15-17/2003	2.45	1.71	0.61	1.90	1.50
Calpine /Creed Energy Center (49.9 MW) 6150 Creed Rd., Suisun City, CA	Bay Area AQMD	500 MMBtu/hr GE LM6000 PC Sprint gas turbine producing 49.9 MW	Water injection + SCR, oxidation catalyst	1/29-2/1/2003	1.53	1.28	0.14	2.18	0.76
Calpine /Goose Haven Energy Center (49.9 MW) 3853 Goose Haven Rd., Suisun City, CA	Bay Area AQMD	500 MMBtu/hr GE LM6000 PC Sprint gas turbine producing 49.9 MW	Water injection + SCR, oxidation catalyst	1/22-24/2003	2.41	1.59	0.84	1.97	0.42
Northern California Power (49 MW) 12751 Thornton Rd., Lodi, CA	San Joaquin Valley APCD	417 MMBtu/hr GE LM5000 gas turbine producing 49 MW	Steam injection + SCR, oxidation catalyst	July 2000	2.75	11.5	-	0.629	24.49
CalPeak Power Border LLC (49.5 MW) Harvest Rd., San Diego, CA	San Diego Co. APCD	500 MMBtu/hr Pratt & Whitney FT8 “Twin Pac” gas turbines with common generator and exhaust producing 49.5 MW	DLN + SCR, oxidation catalyst	11/9/2001	1.88	6.3	2.28	-	3.36

Table B-2. Emission Source Test Results for Simple-Cycle Power Plant Gas Turbines

Facility Name	Permitting Agency	Basic Equipment	Method of Control	Date Tested	Average Measured Emissions, per turbine (ppmvd @ 15% O_2 unless otherwise noted)				
					NOx	CO	VOC	PM10 (lb/hr)	NH_3
CalPeak Power /Panoche (49.4 MW) 43699 W. Panoche Rd., Firebaugh, CA	San Joaquin Valley APCD	(2) Pratt & Whitney FT8 "Twin Pac" gas turbines with common generator and exhaust producing 24.7 MW each	DLN + SCR, oxidation catalyst	2/19/2002	2.47	1.53	<1.24	2.11 (total)	11.7
				5/13/2002 (retest for NH_3)	2.31	-	-	-	6.01
Wellhead Power Gates LLC (45.4 MW) Huron, CA	San Joaquin Valley APCD	436 MMBtu/hr GE LM6000 gas turbine producing 45.4 MW	Water or steam injection + SCR, oxidation catalyst	3/20/2002	2.7	0.7	0.0	2.620	0.4
Wildflower Energy /Indigo (135 MW) 19th Ave., Palm Springs, CA	South Coast AQMD	(3) 450 MMBtu/hr GE LM6000 Enhanced Sprint gas turbines producing 45 MW each	Steam or water injection + SCR, oxidation catalyst	11/30/2001 and 12/2&6/2001	4.47 (CTG1) 3.80 (CTG2) 3.96 (CTG3)	1.46 (CTG1) 1.47 (CTG2) 1.74 (CTG3)	-	-	4.24 (CTG1) 2.19 (CTG2) 3.46 (CTG3)
GWF Energy LLC /Tracy Peaker Power Plant (169 MW) Tracy, CA	San Joaquin Valley APCD	(2) 990.6 MMBtu/hr GE PG7121 EA gas turbines producing 84.5 MW each	DLN + SCR, oxidation catalyst	5/21/2003 100% load	4.82 (CTG1) 4.76 (CTG2)	0.42 (CTG1) 0.16 (CTG2)	0.39 (CTG1) 0.38 (CTG2)	1.960 (CTG1) 2.034 (CTG2)	7.711 (CTG1) 4.962 (CTG2)
				75% load	4.95 (CTG1) 4.73 (CTG2)	0.38 (CTG1) 0.01 (CTG2)	-	-	-
				50% load	3.49 (CTG1) 4.71 (CTG2)	0.23 (CTG1) 0.00 (CTG2)	-	-	-
				25% load	3.07 (CTG1) 4.41 (CTG2)	0.22 (CTG1) 0.00 (CTG2)	-	-	-
Sacramento Municipal Utility District (77 MW) McClellan Air Force Base, Sacramento, CA	Sac Metro AQMD	927 MMBtu/hr GE Frame 7E PG7931 gas turbine producing 77 MW	Water injection + SCR	1/22-23/2001 Full load	3.99	1.54	7.24	4.826	2.41
				Part load	-	33.97	7.24	-	-
				March 2001 Full load	-	-	1.03; 1.21 lb/hr	-	-
				Part load	-	20.7; 30.38 lb/hr	0.83; 0.70 lb/hr	-	-
PG&E Dispersed Generating Company /Chula Vista (44 MW) 3497 Main St., Chula Vista, CA	San Diego Co. APCD	688 MMBtu/hr Pratt & Whitney FT4/GG4 "Twin Pac" gas turbines producing 44 MW	DLN + SCR, oxidation catalyst	6/26/2001	3.16	56.8	2.1	-	8

Table B-2. Emission Source Test Results for Simple-Cycle Power Plant Gas Turbines

Facility Name	Permitting Agency	Basic Equipment	Method of Control	Date Tested	Average Measured Emissions, per turbine (ppmvd @ 15% O_2 unless otherwise noted)				
					NOx	CO	VOC	PM10 (lb/hr)	NH_3
Gilroy Energy Center Phase I (135 MW) at the Calpine Gilroy Power Plant, Gilroy, CA	Bay Area AQMD	(3) 467.6 MMBtu/hr GE LM6000PC gas turbines producing 45 MW each	Water injection or DLN + SCR, oxidation catalyst	**CTG1** 2/1,4,5/2002	3.46	0.62	0.37	-	1.45
				CTG2 2/7-8/2002	3.27	0.70	0.79	-	1.33
				CTG3 3/14-15/2002	3.62	0.49	0.24	-	0.87
Wildflower Energy /Larkspur (135 MW) Harvest Rd., Otay Mesa area, San Diego, CA	San Diego Co. APCD	(2) 395 MMBtu/hr GE LM6000 PC Sprint gas turbines producing 45 MW each	Water injection + SCR, oxidation catalyst	8/28/2001	4.49 (CTG1) 4.56 (CTG2)	38.24 (CTG1) 47.81 (CTG2)	<0.96 (CTG1) <0.96 (CTG2)	-	37.4 (CTG1) 36.6 (CTG2)
				CTG1 1/18/2002	4.16	12.8	<1.00	-	1.33
				CTG2 12/20/2001	3.39	14.6	<0.96	-	1.4
Tampa Electric Company /Polk Power Station (165 MW) Mulberry, Polk Co., FL	FL Dept. of Envir. Protection	1,600 MMBtu/hr GE PG7241FA gas turbine producing 165 MW	DLN	10/7/2000 100% load	7.58	0.24	0.11	-	NA
				85% load	6.18	0.31	0.17	-	NA
				70% load	6.34	0.42	0.33	-	NA
				50% load	5.30	1.31	0.41	-	NA
Sunrise Power Company Phase I (320 MW) Kern Co., CA	San Joaquin Valley APCD	(2) GE Frame 7FA gas turbines producing 165 MW each	DLN	**CTG1** 7/9/2001	6.79	0.49	<0.81	3.52	NA
				CTG2 7/12/2001	6.38	0.47	<0.76	1.91	NA

APPENDIX C

Table C-1. Area Designations for State PM2.5 Ambient Air Quality Standard

Air Basin	Area Included	Designation
Mojave Desert	Central San Bernardino County (portion of San Bernardino County within the federal Modified AQMA for ozone)	N
Mountain Counties	Plumas County	N
Sacramento Valley	Butte and Sacramento counties, portion of Placer County within air basin	N
Salton Sea	Imperial County	N
San Diego	Entire air basin	N
San Francisco Bay Area	Entire air basin	N
San Joaquin Valley	Entire air basin	N
South Central Coast	Ventura County (including Anacapa and San Nicolas islands)	N
South Coast	Entire air basin (including San Clemente and Santa Catalina islands)	N
Lake County	Entire air basin	A
Great Basin Valleys	Entire air basin	U
Lake Tahoe	Entire air basin	U
Mojave Desert (remainder)	Portion of Kern County, portion of Los Angeles County, portion of Riverside County within air basin	U
Mountain Counties (remainder)	Amador, Calaveras, Mariposa, Nevada, Sierra, and Tuolumne counties; portion of El Dorado County; portion of Placer County within air basin	U
North Central Coast	Entire air basin	U
North Coast	Entire air basin	U
Northeast Plateau	Entire air basin	U
Sacramento Valley (remainder)	Colusa, Glenn, Shasta, Sutter, Tehama, Yolo, and Yuba counties; portion of Solano County within air basin	U
Salton Sea (remainder)	Portion of Riverside County within air basin	U
South Central Cost (remainder)	San Luis Obispo and Santa Barbara counties (including San Miguel, Santa Barbara, Santa Cruz, and Santa Rosa islands)	U

A = Attainment; indicates no violations of the State standard in the area during the previous three years.
N = Nonattainment; indicates at least one violation of the State standard in the area during the previous three years.
U = Unclassified; indicates data are not sufficient for determining attainment or nonattainment.

APPENDIX D

Comment Letter 1 from Mitsubishi Power Systems, Inc.

Subject: RE: noxlegrpt Draft Report Available for Comment
Date: Wed, 31 Mar 2004 14:25:23 -0800
From: "Fusato Dana" <fdana@mhia.com>
To: <mbueto@arb.ca.gov>
CC: <ahattori@mhia.com>

Merrin,

Thank you for sending us the draft copy of the report.
I have read the copy and have only one comment.

Page 23 of the draft, 2nd sentence. Please correct the sentence to read: "Ammonia is injected into the combustion turbine exhaust through the ammonia injection grid (AIG)."

Thanks
Fusato Dana
Sr Sales & Marketing Administrator
Mitsubishi Power Systems, Inc.
100 Bayview Circle, Suite 4000
Newport Beach, CA 92660

Comment Letter 2 from Lindh & Associates

Subject: noxlegrpt Draft Report
Date: Thu, 25 Mar 2004 08:49:04 -0800
From: "Chuck Solt" <chuck@csolt.net>
To: <mbueto@arb.ca.gov>
CC: "Stephanie Kato" <skato@arb.ca.gov>,
"Michael Tollstrup" <mtollstr@arb.ca.gov>

I would like to make 2 comments on the report:

Under “Findings” (Page 3), I suggest changing as shown:

The Xonon Cool Combustion system has shown to be an effective pollution prevention device that can achieve NOx emission levels required as BACT in California for simple-cycle gas turbine power plants without the associated environmental impacts from ammonia use; however, the technology has limited applications at this time.

My understanding was that the primary issue of the document is to examine the environmental benefits of using a NOx control technology that does not use ammonia. To that end, I suggest you compare the total ammonia emissions in California with the ammonia slip from SCR.

Thank you for your consideration.

Chuck Solt
J C Solt Lindh & Associates

Comment Letter 3 from Power Systems Mfg., LLC

Jeff Benoit
Director - Combustion Engineering
Power Systems MFG., LLC
A Calpine Company
1440 West Indiantown Rd.
Suite 200
Jupiter, FL 33432

3. Low Emissions Combustor (LEC-III^{TM}) System

Power Systems Mfg. LLC, a subsidiary of San Jose, CA based Calpine Corporation, has developed its proprietary Low Emissions Combustor III (LEC-III^{TM}) system that produces low single-digit NOx and CO emissions on natural gas without post-combustion controls.

a. Technology Description

The LEC-III^{TM} is a patented aftermarket system designed to be a “drop-in” replacement for existing GE frame gas turbine combustors outfitted with either diffusion or DLN combustors. Power System’s lean, premixed combustion design involves premixing of fuel and air in the combustion system through innovative fuel gas injection methods and liner design. A forward-cooling flow venturi (the flame holder) in the combustion liner injects spent cooling air directly into the liner’s head end premixing chamber—reducing CO spikes at machine part load conditions. In addition, efficient cooling of the combustion liner is achieved through effusion cooling, where over 5,000 dimensionally controlled holes arrayed around the head end of the liner eliminate the need for thermal barrier coating. This improves cooling air requirements, aides in fuel/air mixing and provides a more uniform thermal environment. The liner design allows for excellent heat transfer performance, low metal temperatures, and reduced NOx and CO emissions.

b. Emission Performance

The LEC-III^{TM} liner system was first installed in an existing 70-MW GE Frame 7EA gas turbine at TransAlta Cogeneration in Alberta, Canada, in 2001. Prior to the retrofit, the lowest emission levels from the turbine were reported at 17 ppmvd NOx and 14 ppmvd CO at 15% O_2. After installation of the LEC system, emission levels of 6 ppmvd NOx and 2.5 ppmvd CO (average) at 15% O_2 were measured. The turbine has since undergone a 24,000-hour major overhaul, which included removal and return of the hardware to the manufacturer for refurbishment. Reinstallation is planned for September 2004.

The second installation of the LEC-III^{TM} liner system occurred in March 2003 at Dow Chemical's Power 8 facility in Freeport, Texas, on a 83-MW GE Frame 7EA gas turbine. The manufacturer offered an 8-ppmvd NOx guarantee with a design target of 5 ppmvd at 15% O2. Testing was conducted in April 2003 and emission levels of 4.75 ppmvd NOx at 15% O_2 were reported while the turbine was operated without duct burners. During duct burner firing, NOx emissions were between 6.75 to 9.09 ppmvd at 15% O_2, all with CO emissions below 1 ppmvd at 15% O_2. NOx emissions over the entire premixed operation gas turbine load range were below 5 ppmvd at 15% O2.

Two additional units will go into service in Texas in 2004.

c. Commercial Availability

The product is offered commercially for the GE Frame 7E/EA (85.4 MW) and GE 6B (42.1 MW) turbines. The guaranteed NOx and CO emission concentrations in the exhaust are 5 ppmvd at 15% O_2 for both pollutants. The system is under development for the Siemens Westinghouse 501D5 gas turbine (173 MW), Additional development programs in 2004 involve the use of hydrogen-fuel blending to help drive emissions down to 2ppm NOx as well as continued work on LEC systems for the GE 7FA (170 MW) and Siemens Westinghouse 501FD2 (283 MW) machines.

Comment Letter 4 from Sacramento Municipal Utility District

Subject: Gas-Fired Power Plant NOx Emissions - Draft Report to the Legislature (March 2004)
Date: Wed, 7 Apr 2004 14:18:31 -0700
From: "Stu Husband" <SHusban@smud.org>
To: <mbueto@arb.ca.gov>
CC: "Ross Gould" <RGould@CORPORATE.smud.org>

Ms. Bueto:

Thank you for the opportunity to comment on the referenced draft report. SMUD owns and controls approximately 500 MW of gas-fired generation capacity in the greater Sacramento area. Our comments focus primarily on pages A-9 and B-6 of the draft report. On those pages, information is presented for SMUD's 77 MW gas turbine generator located at McClellan Park (formerly McClellan Air Force Base). Please note that this is an industrial frame natural gas-fired gas turbine in simple cycle configuration with water injection NOx control technology, and was originally installed in 1986. In 2000, SMUD retrofit the unit with SCR to reduce NOx emissions and increase permitted operational flexibility. Due to performance problems with the original SCR installation, the unit's SCR system is currently being rebuilt including catalyst replacement. Hence, this facility does not meet the intended scope of the report stated on page 2 as being "new" power plant installations. From that perspective, SMUD believes that it may not be appropriate to include information for the McClellan turbine facility in this report.

However, in lieu of deleting the McClellan turbine facility from the report, the following comments pertain to the table columns presenting CO and VOC information. On Table A-2 (page A-9), emission limits for CO and VOC are listed as 23 ppm and 2 ppm, respectively. This is not correct. Our air permit does not contain CO or VOC concentration emission limits. For CO and VOC, our air permit contains mass emission limits only. These are 46.98 lb/hr CO and 2.36 lb/hr VOC, both on a 3-hr average basis.

On Table B-2 (page B-6), CO and VOC source test results are presented in concentration units. Although not specified in the table, the first set of CO/VOC values (1.54 ppm CO / 7.24 ppm VOC) was at full load operation and the second set of values (33.97 ppm CO / 19.24 ppm VOC) was at part load operation. Due to problems with the initial source testing conducted on 1/22-23/2001, SMUD did not believe these results were representative and the unit was retested in March 2001 with the following results:

* CO part load - 20.7 ppm corrected and 30.38 lb/hr
* VOC part load - 0.83 ppm corrected and 0.70 lb/hr
* VOC full load - 1.03 ppm corrected and 1.21 lb/hr

Other comments for your consideration are as follows:

*	Pages 31-32, Catalyst Washing - The report presumes disposal of catalyst wash wastewater in a public sewer system. Many power plants do not have ready access on site to a public sewer system. In this case, options could include disposal of wastewater to land or surface water if allowed by applicable water quality regulations. This option may be constrained due to stringent water quality release criteria, particularly where NPDES surface water discharge permits are involved. Another option could be to transport the wastewater to an off-site disposal facility or public sewer system that will accept the wastewater.

Please do not hesitate to contact me if there are any questions on these comments.

Stu Husband
Regulatory Compliance Coordinator, Power Generation
Sacramento Municipal Utility District
6201 S Street, MS-B355
Sacramento, CA 95817-1899

Comment Letter 5 from South Coast Air Quality Management District

Subject: NOx Controls Report
Date: Wed, 7 Apr 2004 13:41:47 -0700
From: "Howard Lange" <HLange@aqmd.gov>
To: <mbueto@arb.ca.gov>

In the discussion of ammonia impacts, it would be useful to explain what is included in the various non-agricultural categories depicted in Figure IV-1, i.e., mobile, industrial, soil, waste, domestic. If ammonia inventory from NOx controls is such a tiny fraction of total ammonia inventory even in non-agricultural areas, as this figure suggests, it would seem that we should not be placing much emphasis on ammonia limits on sources that use ammonia for NOx control. In the permits reflected in Appendix A, the trend seems to be toward increasingly more stringent ammonia limits. Is this really productive in most cases? Perhaps the report could provide a little more guidance on this.

Howard B. Lange, Air Quality Engineer
South Coast Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765-4182

Comment Letter 6 from Catalytica Energy Systems

Subject: [Fwd: FW: Leg Report]
Date: Tue, 13 Apr 2004 16:03:30 -0700
From: Beverly Werner <bwerner@arb.ca.gov>
To: Merrin Bueto <mbueto@arb.ca.gov>

Subject: RE: FW: Leg Report
Date: Tue, 13 Apr 2004 13:57:29 -0700
From: DHatfield@CatalyticaEnergy.com
To: bwerner@arb.ca.gov
CC: mtollstr@arb.ca.gov

- The Xonon Cool Combustion system has shown to be an effective pollution prevention device that can achieve NOx emission levels required as BACT in California for both simple-cycle and combined cycle gas turbine power plants without the associated environmental impacts from ammonia use; however, the technology has limited applications at this time.

Each Xonon combustor is customized to the particular turbine model and application and is defined through a collaborative effort with the turbine original equipment manufacturer (OEM) to integrate the hardware into the design. Xonon is currently only commercially available from Kawasaki Gas Turbines-Americas on a small 1.4 MW gas turbine.

The Xonon system was first designed into the combustor of a 1.4 MW Kawasaki Model M1A-13A gas turbine and began operating at Silicon Valley Power ~~Coporation~~ in Santa Clara, California, in 1999. Since its installation, the turbine has operated as a demonstration of Xonon's performance and as a development and test unit in support of commercial program initiatives for customers. More than 18,000 hours of Xonon performance data has been accumulated on the demonstration unit.

As a result of a collaborative agreement announced in December 2000, Kawasaki Gas Turbines-Americas markets and sells a GPB15X generator package including a 1.4-MW M1A-13X gas turbine equipped with Xonon. Kawasaki will provide a performance guarantee for NOx of 3.0 ppmvd and 10.0 ppmvd at 15% O_2 on a continuous basis over a 70-100 percent turbine operating load.

Comment Letter 7 from California Council for Environmental and Economic Balance (CCEEB)

CALIFORNIA COUNCIL FOR ENVIRONMENTAL AND ECONOMIC BALANCE

COMMENTS REGARDING ARB'S DRAFT REPORT TO THE LEGISLATURE: GAS-FIRED POWER PLANT NOx EMISSION CONTROLS AND RELATED ENVIRONMENTAL IMPACTS

(March 2004 ARB Draft)

(Comments Submitted April 13, 2004)

The California Council for Environmental and Economic Balance ("CCEEB") is a nonprofit, nonpartisan coalition of business, labor and public leaders that works to advance policies that protect public health and the environment while also allowing for economic growth. Some of CCEEB's members own and operate power plants in California. Following are CCEEB's comments regarding the March 2004 draft of the Air Resources Board's ("ARB's") Report to the Legislature: Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts.

1. **General Comment**

The draft report is a well-written and well-organized document.

2. **Caveats**

ARB indicates (at Pages 2 and 3 of the draft) that the report:

a. "is not intended to establish new BACT emission levels or certify or validate any emission levels purported to be achieved at various facilities."

b. "does not include conclusions or recommendations."

c. "provides information that can be used as a starting point in conducting more detailed site-specific analyses of the environmental advantages and disadvantages of control technologies that reduce NOx emissions from natural gas-fired power plants."

CCEEB supports the inclusion of these important caveats in the report.

3. **Proposed Finding regarding SCONOx**

A. BACT Emission Levels

As explained below, CCEEB has strong concerns regarding how the draft report characterizes the ability of SCONOx to meet Best Available Control Technology ("BACT") emission limitations for power plants. As context for this section, we emphasize that a key element of whether a technology meets a BACT limit is the "achieved in practice" element. This element ensures that a technology will reliably meet the BACT emission limitation for the application in question so that the high compliance costs will not be wasted.

At the first bullet on Page 3, ARB proposes to state that:

> "The SCONOx catalytic absorption system produces beneficial NOx, carbon monoxide (CO), and volatile organize compound (VOC) emission reductions without the associated environmental impacts from ammonia use and **can achieve emissions levels required as BACT in California."**

Similarly, at Page 9, ARB proposes to state:

> "(…) the control technologies described in this chapter are those that **have the ability to meet or that facilitate meeting** the ARB's recommended BACT emission levels for power plant gas turbines."

Our concern is that these statements could mislead a reader (including Legislators and staff of the State Legislature) into believing that SCONOx will work reliably in meeting BACT and in its operation for **all** power plant situations – which is not the case. We appreciated that this is not ARB's intent, but **it is critical that a report to the Legislature be transparent as to what is really the current status of the technology for meeting BACT limits**.

Table III-3 on Page 16 and the text on Pages 16 and 17 include useful information regarding SCONOx. They note that the "SCONOx system is installed at a total of seven sites in the United States." The use of SCONOx at these plants involves the generation of from 43 MW down to 5.2 MW (i.e., smaller applications). At Pages 16 and 17, ARB includes a discussion of the installation experience at these plants. What is missing from the Executive Summary finding and the related text of the report is a discussion of the lack of experience (and BACT determinations) for use of SCONOx in larger applications. In the CEC's power plant licensing process, significant issues have arisen as to the reliability and scope of vendor guarantees for SCONOx for larger utility-grade operations.

CCEEB urges ARB to clarify in both the Executive Summary and the supporting text of the report that SCONOx has been demonstrated to meet BACT for some applications but has not been shown to meet BACT for all power plant applications including larger applications. On a related note, we support ARB's inclusion of the statement on Page 33 that the "SCONOx system is not available for use in simple-cycle configurations because the turbine exhaust temperatures are outside the effective range of the control technology."

Please note that our comments in this area are not intended as a criticism of SCONOx. CCEEB recognizes the benefits of SCONOx for the commercial applications for which it has been demonstrated to meet BACT levels (and for which a vendor will provide a guarantee to that effect). Our concern is that future legislative and regulatory requirements for controls for new power plants must tied to emission levels that have been "achieved in practice" for the application in question. This is necessary to assure that large environmental compliance investments made during the construction of new power plants are not wasted. It is critical that the Legislature understand the complete picture in this area.

B. Environmental Impacts

As noted above, at the first bullet on Page 3, ARB proposes to state that:

> "The SCONOx catalytic absorption system produces beneficial NOx, carbon monoxide (CO), and volatile organize compound (VOC) emission reductions without the associated environmental impacts from ammonia use and can achieve emissions levels required as BACT in California."

In addition to the concerns raised above, we are concerned that from reading this proposed finding and the other proposed findings in the Executive Summary, a person might conclude that there are no environmental impact issues associated with SCONOx. With regard to both the findings and the text regarding environmental issues associated with SCONOx at Pages 31-32, we suggest that ARB may want to add information regarding the handling of hydrogen and potential emissions of H_2S and SO_2.

4. The Differences in Cost of Controls

In the last bullet on Page 4, ARB proposed to state that:

> "Available cost data indicates that SCR used in conjunction with an oxidation catalyst costs less than SCONOx for the same level of emission reduction."

In the supporting text on Page 33, ARB proposes to state that:

> "Cost figures show that the SCR/oxidation catalyst package is less than the SCONOx system."

First, CCEEB supports inclusions of such statements in the report. It is important that the Legislature be aware of the cost differences. Second, we note that the two statements are accurate, but they do not convey that the estimated cost differences are substantial. In Table V-1, the data indicates that for a 500-MW combined-cycle gas turbine power plant, the capital cost for SCONOx may be over three times as much as SCR/CO (i.e., $20,747,637 for SCONOx and $6,259,857 for SCR/CO). The table indicates that the annual operation and maintenance costs for SCONOx may be over double same costs for SCR/CO (i.e., $3,027,653 per year for SCONOx and $1,355,253 per year for SCR/CO).

We suggest that ARB be more explicit regarding the cost differences. One way to accomplish this would be to insert the word "significantly" before the word "less" in the two above-quoted sentences.

Also, with regarding to Table V-1, the table is labeled as “Estimated Average Cost of Post-Combustion Control Technology for a 500-MW Combined-Cycle Gas Turbine Power Plant meeting BACT.” As noted previously, the text and Table III-3 on Page 16 indicates that the “SCONOx system is installed at a total of seven sites in the United States.” The seven plants are plants with 43 MW or less (i.e., plants that are much smaller than 500 MW plants). Based on that information, we expect that the “estimated average cost of post-combustion control technology for a 500-MW Combined-Cycle Gas Turbine” is based on a scaling up of costs for SCONOx for smaller plants – and there are no real cost numbers for installed SCONOx for a 500-MW power plant. Assuming this is the case, we recommend that ARB note this clearly and note that the estimates are hypothetical numbers based on scaled-up data, and that inclusion of the table does **not** imply that a 500-MW combined cycle gas turbine power plant meeting BACT limits with SCONOx exists.

5. Stratospheric Ozone Depletion

In the second paragraph on Page 6, the draft report states that NOx emissions are of particular concern due to their contribution to “ground-level ozone formation, stratospheric ozone depletion, and acid rain.” Our understanding is that NOx is **not** a compound that is regulated as a stratospheric ozone-depleting compound. (Please see http://www.epa.gov/ozone/ods.html.) Further, the issue of stratospheric ozone depletion is beyond the scope of the requested report. CCEEB suggests that ARB delete the reference to stratospheric ozone depletion from this sentence.

CCEEB appreciates ARB’s consideration of these comments. If you have any questions, please contact Cindy Tuck at (916) 442-4249.

Comment Letter 8 from Florida Power & Light Group

Subject: Gas Fired NOx emissions controls draft report.
Date: Tue, 13 Apr 2004 13:52:29 -0400
From: Kyle_Boudreaux@fpl.com
To: mbueto@arb.ca.gov

My name is Kyle Boudreaux and I work for FPL Group, Juno Beach, FL. A subsidiary of our company, FPL Energy, owns a gas fired power plant in Blythe, CA. In addition, our corporation has developed numerous gas fired power plants in several states outside of Florida and have re-powered several of our Florida facilities to run on natural gas. We have been recognized by Innovest for the past three years as the top performer in environmental excellence among electric utilities in the US. Everyone of our environmental experts that I showed your draft document to agreed with the majority of the information in your report. The individuals who prepared this report for the California Air Resources Board did an excellent job. The document is obviously the result of a well designed plan to research and gather information on NOx controls for gas fired power plants. The only suggestion I received for a possible improvement is related to SCONOX technology and large combustion turbines. The report seems to indicate that SCONOX is a commercially viable and technically feasible technology. We have not found this to be the case for large combustion turbines in our fleet. Typically, the reaction chambers are complex, the maintenance costs are high and we are not aware of the technology being proven to work on larger units. We know that the technology is being developed and there is a permit application in process for one of these units in San Joaquin County, but we do not feel SCONOX has reached the level of reliability and economic feasibility as other technologies for these larger turbines.

Thank You,

Kyle Boudreaux
Sr Environmental Specialist
Environmental Services

Comment Letter 9 from Cormetech

Subject: Comments on ARB Draft Report to Legislature
Date: Tue, 13 Apr 2004 18:04:21 -0400
From: "Hastings, Thomas W." <HastingsTW@Cormetech.com>
To: <mbueto@arb.ca.gov>
CC: <skato@arb.ca.gov>

Comments on Section III.D.2 - Zero-Slip(TM) Ammonia Reduction Technology, Emission Performance

The Zero-Slip(TM) technology is described well in the first paragraph. After the description, there is a focus on VOC issues and no direct mention of emission performance for NOx, CO, and NH3. The NOx and CO emissions have been below the permit levels. The NH3 emission level was measured as 0.1 ppmvd or less which is well below the permit level of 5 ppmvd.

On the VOC issues, the Zero-Slip(TM) technology installed at the Paramount Petroleum site in SCAQMD was designed for zero VOC. If a design requirement for VOC had been indicated, the CO catalyst would have been formulated to handle both CO and VOC.

Thanks and best regards . . . Tom.

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